

From: Kukla, Alison
Location: Alm Conference Room
Importance: Normal
Subject: Meetings with EEI
Start Date/Time: Thur 9/5/2013 1:00:00 PM
End Date/Time: Thur 9/5/2013 3:00:00 PM

SCT: Alison Kukla

EEI Ct: Brian Wolff, Senior VP - bwolff@eei.org, 202-508-5300

Staff:

Nichole Distefano (OCIR)

Michael Goo (OP)

Ken Kopocis (OW)

Janet McCabe, Joe Goffman, Peter Tsirigotis, Ellen Kurlansky (OAR)

Deputy Administrator, Lisa Feldt, Arvin Ganesan (OA)

Attendees:

Michael Yackira	CEO	NV Energy
Thomas Farrell	Chairman, President, CEO	Dominion
Thomas Fanning	Chairman and CEO	Southern Company
Nick Akins	President and CEO	American Electric Power
Lew Hay	Executive Chairman	NextEra Energy
Gery Anderson	Chairman, President, CEO	DTE Energy
Ralph Izzo	Chairman and CEO	PSEG
Gregory Abel	Chairman, President, CEO	MidAmerican Energy
Anthony Early	Chairman, President, CEO	PG&E
Pat Collawn	Chairman, President, CEO	PNM Resources
Tom King	President	National Grid
Chrisopher Crane	President and CEO	Exelon
Tom Kuhn	President	EEI
Brian Wolff	Senior Vice President	EEI
Quin Shea	Vice President, Environment	EEI
Marv Fertel	President and CEO	NEI
Micheal Jay Bradley	President and Founder	MJB&A
Ann Loomis	Senior Advisor for Federal & Environmental Policy	Dominon
Randall LaBauve	Vice President of Environmental Services	Florida Power & Light Company
Kristen Ludecke	Vice President, Federal Affairs	PSEG

Run of Show:

9AM: 316(b)

10AM: GHG NSPS Issues

From: Echols, Mabel E.
Location: 1800 G Street, NW - Conference Room 2
Importance: Normal
Subject: E.O. 12866 Meeting on Carbon Pollution Emission Guidelines for Existing Stationary Sources:
Electric Utility Generating Units
Start Date/Time: Mon 7/27/2015 2:00:00 PM
End Date/Time: Mon 7/27/2015 2:30:00 PM

;

This meeting was requested by Tom Lawler, Lawler Strategies on behalf of Dominion Resources.

Call-in: code

To: John McManus[jmmcmanus@aep.com]
Cc: McCabe, Janet[McCabe.Janet@epa.gov]; Andrea Field[afield@hunton.com]; Atkinson, Emily[Atkinson.Emily@epa.gov]
From: Drinkard, Andrea
Sent: Wed 6/11/2014 5:20:15 PM
Subject: RE: Invitation to June UARG Planning Workshop
[Janet McCabe Event Form AAA.docx](#)

Thanks, John. Just following up with the form. If you could fill it out and get it back to us this week that'd be great.

-Andrea-

Andrea Drinkard
U.S. Environmental Protection Agency
Office of Air and Radiation
Email: drinkard.andrea@epa.gov
Phone: 202.564.1601
Cell: Personal Cell/email

-----Original Message-----

From: John McManus [mailto:jmmcmanus@aep.com]
Sent: Saturday, June 07, 2014 12:58 PM
To: Drinkard, Andrea
Cc: McCabe, Janet; Andrea Field
Subject: Re: Invitation to June UARG Planning Workshop

Andrea - 9 am on the 20th will definitely work, and a full hour will be great. Thanks for checking Janet's schedule and getting back to us.

John McManus

> On Jun 6, 2014, at 6:36 PM, "Drinkard, Andrea" <Drinkard.Andrea@epa.gov> wrote:
>
> This is an EXTERNAL email. STOP. THINK before you CLICK links or OPEN attachments.
>
> *****
> Hi John,
>
> Apologies for the delay in getting back to you. It's been a busy couple of weeks. I just spoke with Janet and checked the calendar and it looks like she'd be available at 9am on Friday, June 20. Would that time work for you? I assume you'd want her for the hour.
>
> If so, I'll forward a form for you all to fill out on Monday so we can prep for the event.
>
> Thanks so much and hope you have a wonderful weekend!
>
> Andrea Drinkard
> Deputy Communications Director
> EPA Office of Air and Radiation
> 202.564.1601
>
> Original Message
> From: John McManus
> Sent: Friday, June 6, 2014 4:43 PM

> To: McCabe, Janet
> Cc: Andrea Field; Drinkard, Andrea
> Subject: RE: Invitation to June UARG Planning Workshop
>
> Janet - I thought I would check in on the invitation below to the UARG Annual Planning Workshop, which is two weeks away. I am sure the past couple of weeks have been incredibly hectic for you. Hopefully, things will settle down some with the proposal out and your schedule will allow some time to join us. Obviously there is a lot worth talking about.
>
> Thanks.
>
> John
>
>
> -----Original Message-----
> From: McCabe, Janet [mailto:McCabe.Janet@epa.gov]
> Sent: Saturday, May 17, 2014 1:13 PM
> To: John McManus
> Cc: Andrea Field; Drinkard, Andrea
> Subject: Re: Invitation to June UARG Planning Workshop
>
> This is an EXTERNAL email. STOP. THINK before you CLICK links or OPEN attachments.
>
> *****
> John--thanks so much for the invitation. We will scan the calendar quickly and get back to you.
>
>

> From: John McManus <jmmcmanus@aep.com>
> Sent: Friday, May 16, 2014 8:08:26 PM
> To: McCabe, Janet
> Cc: Andrea Field
> Subject: Invitation to June UARG Planning Workshop
>
> Janet - it was good to talk to you yesterday. I am following up on my verbal invitation to the UARG Planning Workshop. The workshop begins at 1 pm on Thursday, June 19 and goes to 5 pm. We resume Friday morning June 20 at 8 am and go to noon. Our membership would very much appreciate the opportunity to have a dialogue with you on the key Clean Air Act programs that affect our industry. This would include the 111(d) proposal, assuming it is issued early in the month, implications of the CSAPR decision and anything you can share about the Agency's next steps, the rapidly approaching MATS compliance deadline, and other issues. Our agenda is flexible and we can accommodate your schedule if you are available.
>
> We look forward to hearing from you.
>
> John

From: Goffman, Joseph

Location: DCRoomARN5415PolyPCTB/DC-ARN-OAR | 1200 Pennsylvania Avenue, NW, William Jefferson Clinton Federal Building, Washington, DC 20460

Importance: Normal

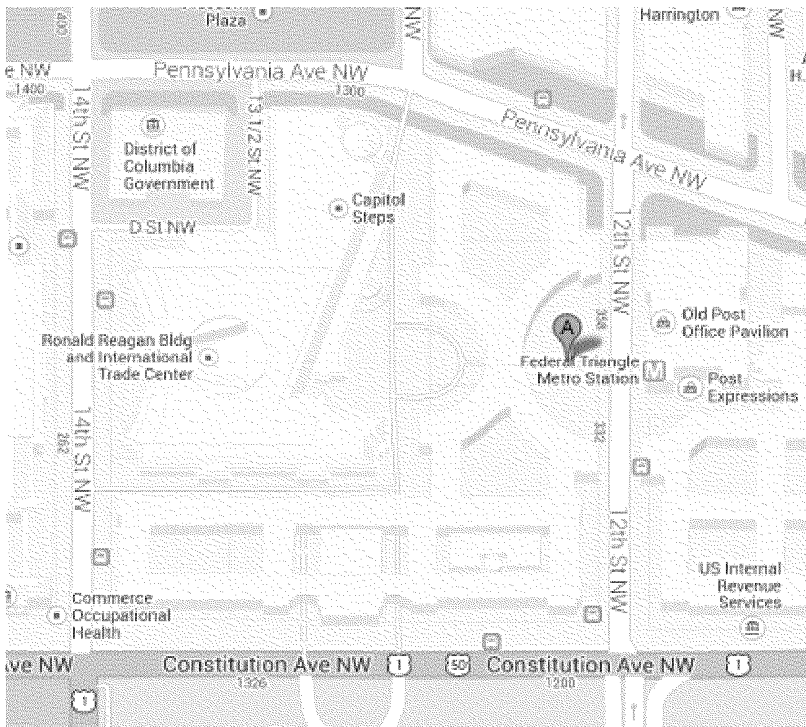
Subject: Meeting Re: UARG Response to EPA 111(d) Questions | WJCN 5415 | Conference: 1-

Conf Code Participant Code **Conf Code**

Start Date/Time: Thur 12/12/2013 7:00:00 PM

End Date/Time: Thur 12/12/2013 8:00:00 PM

FW: UARG Response to EPA 111(d) Questions; request for dialogue

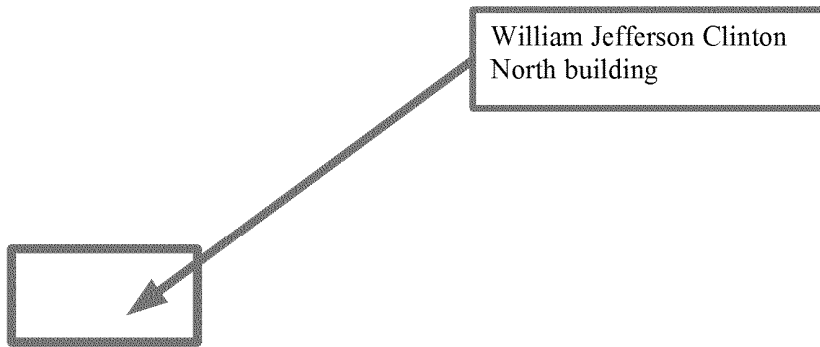


Directions and procedures: If you come by Metro the Federal Triangle metro stop is directly below the building entrances. You would leave the metro station and go up all three sets of escalators and turn right. You will see a set of stairs and glass Doors with EPA Signified on Glass. That is William Jefferson Clinton North (formerly Ariel Rios)

If you are coming by taxi, you would want to be dropped off on 12th NW, between Constitution Ave and Pennsylvania Ave. It is almost exactly half way between the two avenues on 12th. From 12th Street, facing the building with the EPA and American flags, walk toward the building and take the glass door on your right hand side with the escalators going down to the metro on your left. This again will be the North Lobby of the William Jefferson Clinton North.

Upon entering the lobby, the meeting attendees will be asked to pass through security and provide a photo ID for entrance. Let the guards know that you were instructed to call 202-564-7400. If you are travelling in a large group, you may want to arrive 10-15 minutes early in order to be on time for the meeting.

Map:



**COMMENTS OF THE EDISON ELECTRIC INSTITUTE
ON CARBON POLLUTION EMISSION GUIDELINES
FOR EXISTING STATIONARY SOURCES:
ELECTRIC UTILITY GENERATING UNITS**

Docket No. EPA-HQ-OAR-2013-0602

December 1, 2014

The Edison Electric Institute (EEI) submits these comments on the proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units issued by the Environmental Protection Agency (EPA or Agency) in Docket No. EPA-HQ-OAR-2013-0602. 79 *Fed. Reg.* 34,830 (June 18, 2014).¹ EPA subsequently issued a Notice of Data Availability that provided additional information and solicited comments on several topics raised by the proposed guidelines. *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Notice of Data Availability*, 79 *Fed. Reg.* 64,534 (Oct. 30, 2014) (NODA).²

In these proposed emission guidelines, issued under Clean Air Act (CAA or Act) section 111(d), EPA proposes state-specific emission rate goals aimed at reducing the average carbon dioxide (CO₂) emission rate of each state's fleet of existing affected fossil-based electric generating units (EGUs). After the guidelines are final, states will be required to submit compliance plans for EPA approval that demonstrate how they will achieve these goals.

¹ EPA subsequently extended the comment deadline to December 1, 2014. *See Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, 79 *Fed. Reg.* 57,492 (Sept. 25, 2014).

² In the same docket as the proposed guidelines, EPA also issued *Carbon Pollution Emission Guidelines for Existing Stationary Sources; EGUs in Indian Country and U.S. Territories; Multi-Jurisdictional Partnerships*, 79 *Fed. Reg.* 65,482 (Nov. 4, 2014) (Supplemental Proposal). Where appropriate, issues raised in this Supplemental Proposal are addressed in these comments.

EEI is the association that represents all U.S. investor-owned electric companies, international affiliates and industry associates worldwide. Our members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers. With more than \$90 billion in annual capital expenditures, the electric power industry is responsible for millions of additional jobs. Reliable, affordable and sustainable electricity powers the economy and enhances the lives of all Americans. As generators of electricity and the operators of the nation's electric transmission and distribution (T&D) system, EEI member companies have a critical interest in the proposed state guidelines for existing EGUs. As discussed in these comments, the proposed guidelines envision dramatic changes to the ways in which electricity is produced, transmitted and consumed.

I. Introduction And Executive Summary.

EPA's proposed section 111(d) guidelines for existing steam EGUs and combustion turbines (CTs) set state-specific CO₂ emission rate goals that must be achieved by 2030, with an interim rate goal that must be achieved over the period 2020-2029. *See 79 Fed. Reg.* at 34,836-37. As required by the CAA, any proposed goals must reflect the emission rates that are achievable through the use of the "best system of emission reduction" (BSER) that has been "adequately demonstrated." *See CAA* section 111(a)(1).

EPA's proposed BSER is the combination of four "Building Blocks." These Building Blocks, which form the basis of the proposed state-specific interim and final emission rate goals, quantify reductions from affected fossil-based units, as well as emission reductions that EPA believes could be achieved through heat rate improvements at existing coal-based units; increased dispatch of existing natural gas combined cycle (NGCC) units; use of existing and

increased deployment of new renewable energy (RE) generating technologies; currently under construction nuclear units and the preservation of some existing nuclear units; and decreases in overall electricity usage and demand as a result of expanded end-use efficiency (EE) programs. *See 79 Fed. Reg.* at 34,836. EPA asserts that it is reasonable to base state goals on reductions beyond those that could be achieved at affected units because of the interconnected nature of the power system. *See id.* at 34,880.

EPA's novel "systems" approach to BSER in the proposed guidelines raises legal questions about EPA's authority to base standards for existing units on reductions that can be achieved only by units not regulated under the CAA or through changes in the end-use of a product. Because EGUs cannot, on their own, achieve the level of reductions necessary to comply, the proposed guidelines effectively require states, utilities owning EGUs and, in many cases, consumers and organizations that are totally unrelated to an existing EGU to undertake new programs and measures to meet the emission rate goals. Never before have the BSER provisions of the CAA been applied to authorize EPA to regulate states and markets in this way. These legal issues, which are discussed in more detail in section IV, below, eventually will be addressed by the inevitable litigation of the proposed 111(d) guidelines.

EEI member companies are committed to providing safe, affordable, reliable and increasingly clean electricity to customers. Should EPA's final guidelines survive judicial review, they *must* establish achievable state emission performance goals, provide realistic timeframes to make the system changes necessary to achieve such goals and create a workable framework for state and utility compliance while ensuring the continued provision of reliable electric service to all

customers during all weather conditions. Importantly, the final guidelines also must provide states the flexibility to choose the most cost-effective reductions and to minimize costs for electricity consumers. States and electric utilities must be able to mitigate the potential impact on costs to customers and ensure the overall reliability of the power system. For these reasons, EEI submits these comments addressing EPA's proposed guidelines *as they have been proposed*. The purpose of these comments is to identify issues and concerns with the proposed guidelines and, where possible, to provide proposed solutions to ensure that the emission rate goals can be achieved without compromising the reliability and affordability of electricity. EEI's comments should not be construed as an endorsement of the proposed guidelines and, specifically, EPA's approach to BSER. By design, the proposed guidelines are state-specific, and as a result, individual entities will each address their own specific concerns and approaches to the proposed guidelines.

A. Executive Summary

The member companies of the Edison Electric Institute (EEI) are committed to providing reliable, affordable and increasingly clean electricity that powers the U.S. economy and benefits the lives of customers. As of the end of 2013, the power sector has reduced carbon dioxide (CO₂) emissions 15 percent below 2005 levels. While the power sector continues this transition to cleaner forms of generation, the guidelines that the Environmental Protection Agency (EPA or Agency) has proposed under Clean Air Act (CAA or Act) section 111(d) for states to regulate CO₂ emissions from existing steam electric generators and combustion turbines (collectively, EGUs) would require dramatic and accelerated changes to the ways in which electricity is produced, transmitted and consumed. Accelerating these changes will be excessively costly to customers and threaten the reliability of electric service.

If finalized as proposed, the emission guidelines, particularly the interim goals for 2020, would have a significant impact on customers and the nation in terms of cost and the overall reliability of our electric system. EPA's novel approach to regulation of CO₂ emissions from existing units under section 111(d) raises legal questions. Therefore, should EPA's final guidelines survive judicial review, they must establish achievable state emission rate goals and provide realistic timeframes in which to make the changes to the interconnected power system necessary to achieve these goals, consistent with the power sector's obligation and commitment to providing reliable and affordable electricity. To this end, EEI's comments offer suggestions to alleviate the many issues and concerns many EEI member companies have identified with the proposed guidelines. If adopted, these suggestions would help to mitigate concerns about the impact of the guidelines on member companies' ability to provide reliable and affordable electricity while reducing CO₂ emissions. However, EEI's comments should not be construed as an endorsement of the proposed guidelines, and, specifically, EPA's approach to BSER.

EPA's proposed guidelines for existing EGUs include state-specific emission rate goals. Upon finalization of the guidelines, states will be required to develop plans for EPA approval that demonstrate how emissions from affected EGUs will be reduced to meet these goals. EPA asserts that these goals are achievable because they are based on the "best system of emission reduction" (BSER) that the Agency claims has been "adequately demonstrated," consistent with the requirements of CAA section 111(a)(1). EPA's proposed BSER is comprised of four Building Blocks that seek to reduce emissions not only directly from the regulated existing EGUs, but also indirectly from actions at other sources throughout the interconnected power system that have effects on affected sources.

Because EPA's proposed BSER goes beyond the scope and control of regulated EGUs to require reductions throughout the "electric system" and even beyond the outlet to consumers, a significant portion of EEI's comments is devoted to explaining how the system operates and how electric utilities, states and system operators engage in complex planning to maintain the reliability of the interconnected power system. Maintaining reliability requires more than ensuring adequate reserve margins. In fact, it requires that myriad system needs be met on a second-to-second basis, which requires significant planning and lead time. EPA incorrectly assumes that the accelerated transition envisioned in the proposed guidelines for the existing generating fleet either does not have reliability implications or can be achieved within the time frames EPA has established for interim goals. This is not the case.

According to the North American Electric Reliability Corporation (NERC), the entity charged with maintaining reliability of the power grid, implementing the proposed BSER Building Blocks will require significant changes in the way that the interconnected power system currently is planned and operated. Retiring base load fossil generating units, expanding the use of natural gas-based generating units, increasing the deployment of variable renewable resources, and incorporating increased end-use efficiency and demand response all will have an impact on the grid and the pipeline and other infrastructures the grid depends on. Managing these impacts requires significant time and planning that EPA has not allowed for in the proposed guidelines' compliance schedule.

For each state, EPA proposes both an interim and final emission rate goal. The interim goal is measured via a 10-year averaging period that starts in 2020, which EPA specifically says

“increases state flexibility to choose among alternative potential plan measures.” In order to satisfy the 10-year average goal, many states must achieve more than 50 percent of their 2030 emission reduction goals by 2020; and 11 states—including Arizona, Arkansas, Florida and Minnesota—must achieve more than 75 percent of their 2030 goals by 2020. **This effectively turns the 2030 goal into a 2020 goal for these states.** Thus, contrary to EPA’s stated intent of providing states flexibility to achieve the 2030 emission goals, the interim compliance average goal creates more compliance challenges than it solves.

Eliminating the interim compliance goal and allowing states to determine their own reduction glide paths and milestones to achieve the 2030, or the early action alternative 2025 goals, as part of their compliance plans would provide states with real flexibility to preserve reliability and minimize costs to electricity customers. States and utilities lack sufficient time between now and 2020 to develop plans, design and complete the infrastructure required to accomplish changes in dispatch between coal-based and natural gas-based units and increase deployment of renewable generation or other zero-emitting resources. Eliminating the proposed interim compliance goal would allow states to determine the most cost-effective actions and measures to pursue to achieve the 2030 goals, and to choose a reasonable schedule for implementing those measures consistent with providing safe, reliable, affordable and environmentally responsible power to customers. Similarly, states should have the option to achieve emission reductions earlier by developing plans to implement EPA’s proposed early action 2025 alternative goals.

Numerous arguments support the elimination of the interim compliance period. **EPA's proposed compliance timeline does not allow adequate time for the needed reliability assessments and system changes to be accomplished before 2020**, by which time many states would need to have accomplished significant emission reductions. EPA has not demonstrated that every state can increase utilization of existing natural gas combined cycle (NGCC) units to 70 percent by 2020, as EPA incorrectly assumes that current natural gas infrastructure is sufficient to support this dramatic increase and EPA does not account for the fact that many natural gas units must back up renewable generation. Further, increasing generation from existing NGCC units also may require electric transmission upgrades and expansions. As NERC recently has noted, these projects can take 10-15 years to plan, design, permit and construct.

The interim compliance goals also are inconsistent with state planning processes, market schedules and utility investment decision-making, which generally have much longer planning cycles and asset lives. Further, the proposed interim compliance period does not allow sufficient time for regional transmission organizations (RTOs) and independent system operators (ISOs) to evaluate and potentially alter market rules to accommodate changes in dispatch.

As envisioned in the proposed guidelines, the changes in how demand is met—through increased dispatch of existing NGCC units, increased deployment of renewable generation, the use of existing renewable generation, and increased end-use efficiency—could have implications for the wholesale electricity markets operated by RTOs and ISOs. Because each market has its own set of rules, it is not immediately clear how the RTOs and ISOs will respond to such state plans. RTOs and ISOs will have very little, if any, time to make market changes before 2020.

Eliminating the interim compliance goals would not eliminate the need for states to submit and implement plans to reduce emissions on a reasonable glide path to the 2030 or 2025 goals. EPA’s proposed guidelines already would require that states submit—and that EPA approve—plans that clearly set forth how states would achieve the final goal. Thus, it would be incorrect to assume that the elimination of the interim goals would not result in emission reductions in the 2020-2029 timeframe. States would demonstrate progress toward the final goal consistent with their projected emission reduction glide path, which would include significant milestones through the annual reporting of emission performance to EPA, taking corrective measures if needed. Ultimately, if states could not show reasonable progress toward the final goal, EPA would have the authority to call for a state to correct its plan or issue a federal plan of its own. Taken as a whole, the state plan process set forth in the proposed guidelines, and the requirements of the CAA itself, would ensure that significant, verifiable emission reductions would occur before 2030.

There are a range of options for states to consider when defining approvable emission reduction glide paths. Some of these options include: existing trading programs such as the Regional Greenhouse Gas Initiative (RGGI) and California’s A.B. 32 program; a “safe harbor” from compliance with the interim targets for states that choose to require in-state resources to include a carbon adder pre-determined by EPA when bidding resources into the market; and planned, enforceable coal plant retirements.

To promote maximum state flexibility in the design of approvable compliance plans and to enable states to take into account changed circumstances, **the final guidelines should clarify**

that states can modify plans, subject to EPA approval, to address changing circumstances, thereby giving states the flexibility to incorporate changing and improved technologies that benefit all customers.

In addition to pace and timing, another significant compliance challenge is that **the proposed guidelines fail to recognize the critical role of nuclear and hydropower in reducing CO₂ emissions, and do not incent their continued operation and development.** All zero-emissions generation sources (e.g., nuclear, wind, solar, and hydropower) have climate benefits.

The nation cannot achieve its carbon-reduction goals without the existing nuclear fleet—without the nuclear fleet, carbon emissions will be higher, as will the cost of electricity, natural gas and carbon allowances under a carbon-control regime. Nuclear plants also are critical to the reliability of the electric grid. Yet, the proposed guidelines create no real incentive to maintain existing nuclear power plants. Although EPA notes that some existing nuclear facilities are at risk of premature retirement, the proposed guidelines greatly underestimate the quantity of nuclear generation that is actually at risk in some states, while overstating the amount at risk in other states. If EPA is going to continue with its broad interpretation of BSER, **the Agency should remove the six percent “at risk” factor from the goal calculation.** Instead, EPA should consider alternative approaches for incenting the continued operation of existing nuclear generation capacity.

For nuclear units that are under construction, EPA should include in an expanded definition of “new” nuclear in the final guidelines:

- New nuclear power plants (those currently under construction or others that might be built between now and 2030 and beyond);

- Power uprates at existing nuclear plants, including those undertaken during or after 2012 or a modified baseline period; and
- Nuclear plants relicensed to operate past their initial license terms (i.e., beyond 40 years) that have not received their license renewal from the Nuclear Regulatory Commission (NRC) before the baseline year or period, and nuclear plants relicensed to operate beyond 60 years (subsequent license renewal).

The proposed guidelines also fail to recognize the value of new and imported hydropower—particularly hydropower imported from Canada—in providing affordable, zero-emissions power in certain regions of the country. The final guidelines also should allow states to include generation from “new” hydropower generating capacity in a state’s compliance plans, and should define “new” hydropower broadly to include:

- New hydropower plants that become operational after 2012;
- Power uprates at existing hydropower plants, including those undertaken during or after 2012 or a modified baseline period; and
- Any hydropower facilities relicensed during or after the baseline year or period.

In addition, EPA also should not penalize states that are lowering their carbon emissions by building new nuclear and NGCC units. The output from under-construction nuclear and NGCC units should not be included in the calculation of state emissions rate goals. At minimum, if EPA determines to consider under construction NGCC units when finalizing the state goals, EPA should not assume the same re-dispatch potential of 55 percent for all under construction units.

As a general matter, the design of the proposed guidelines penalizes states and companies that took action before 2012 to reduce emissions by giving these states more stringent goals. **The**

proposed guidelines would penalize leadership in emission reductions, renewable energy and other clean energy programs. In particular, the proposed guidelines would: (1) impose more stringent goals on states that, prior to 2012, retired coal units and replaced them with NGCC units; (2) require greater reductions from states that use NGCCs to balance high levels of renewable generation; and (3) ignore the significant contribution of existing state renewable and energy efficiency programs toward the nation's progress in reducing greenhouse gas emissions. Ironically, the proposed guidelines would impose greater burdens on states that have already implemented the very programs that EPA would like to encourage.

As a policy matter, EPA should allow states to recognize all reductions that occur after 2012, the baseline year selected by the Agency for calculating the state emission rate goals and use these reductions to meet the final goals. Specifically, **the final guidelines should allow states to bank, and then use for compliance, emission reductions that result from new state requirements, measures and programs instituted after 2012 and prior to 2020.**

The final guidelines also should **affirm that states can include in compliance plans emission reductions without reference to whether these reductions were achieved by measures that were “on the books” at the time the guidelines were proposed.** For purposes of the CAA, the relevant question in assessing any reductions that are achieved after 2012 is not *why* reductions were achieved, but *whether* they were achieved.

EEI members companies have identified a range of technical concerns with each of the four Building Blocks that comprise EPA's proposed BSER. **EPA overestimated the potential CO₂**

emission reductions that could result from each of these Building Blocks. In addition to specific issues with EPA's analysis of potential reductions from each Building Block, any assertion of the achievability of the proposed state goals is undermined by the fact that **EPA ignored the interactions between and among the Building Blocks and state-specific constraints when assessing the reduction potential of each Building Block, and, consequently, proposed state emission rate goals may not be achievable.**

For example, the addition of large amounts of variable wind and solar resources under Building Block 3 likely will require increased use of natural gas-based units to provide back-up and ramping services. Units cannot run continuously at high utilization rates and also simultaneously be available to support renewable generation, which requires frequent increases and decreases in generation in response to variable renewable output. If natural gas-based units cannot run at consistently high utilization rates, they may not be able to be used to displace as much coal generation as EPA estimates is possible under Building Block 2.

Similarly, increased utilization of existing NGCC units is intended to reduce the utilization of existing coal-based units, many of which will cycle more often as a result. Because coal-based units have lower emission rates when they run consistently at high capacity factors, increased cycling undermines efforts to improve their heat rates under Building Block 1. EPA's Building Block analysis considered none of these impacts. As a result, the proposed state goals do not realistically reflect electric system operations, as EPA asserted.

Further, EPA's analysis ignored state-specific constraints when calculating the emission rate goals. These state-specific constraints range from challenges related to hot summers in some states, use of inaccurate data, failure to consider existing state programs and insufficient recognition of infrastructure and reliability concerns. To the extent that these issues are identified by states and companies in their comments, **EPA should work with the states to set achievable state goals that reflect in-state conditions, using accurate data. EPA should address these state-specific concerns about the proposed emission rate goals before finalizing these goals.**

Specific concerns with EPA's approach to calculating the reductions potential of each Building Block are discussed in detail in EEI's comments. Some key concerns include:

- EPA's assumption that fleet-wide, existing coal-based units can improve heat rates by four percent through O&M "best practices" is not supported by the Agency's assessment of recent heat rate data and, therefore, is not reasonable.
- EPA has not provided a reasonable basis for concluding that "equipment upgrades" can improve heat rates by two percent.
- EPA overestimated the value of fuel costs savings to an affected EGU.
- EPA's analysis does not support the achievability of increasing NGCC utilization to 70 percent in all states for a sustained period of time.
- EPA drew unsupported conclusions about the achievability of re-dispatch based on limited data regarding historical NGCC operations; relied on inaccurate or inappropriate data; and did not take into account the difference between nameplate capacity factor and demonstrated capacity factor.
- EPA ignored physical, technical and financial constraints in both the natural gas and electric systems in determining the possible levels of re-dispatch to NGCCs by 2020.
- EPA has not considered constraints related to the gas and electric systems' interdependency (especially the fact that many gas pipelines can supply electric generation only for peak summer periods because they must serve heating needs in

winter), and has not demonstrated that the current natural gas pipeline infrastructure can support increased NGCC utilization.

- EPA's reliance on state renewable energy standards (RES) in setting state goals overestimated achievable RE deployment in some states.
- EPA's RES assessment failed to account for the fact that state RES requirements allow the use of existing hydropower, biomass and other sources of renewable generation that EPA does not permit states to use for 111(d) compliance; include multipliers for some types of generation; and allow for alternative compliance payments.
- EPA's use of RE growth rates based on the historic performance of a limited group of states is not reasonable.
- EPA has not provided a reasonable basis for assumptions underlying future estimates of the costs of renewable energy technologies.
- EPA has not assessed the technical challenges associated with increased penetration of renewable generation sufficiently.
- EPA has not demonstrated that the projected EE savings rate or related expenditures are achievable by all states; the experience of three states in 2012 does not demonstrate that this savings rate can be achieved and sustained by all states over the compliance period.
- EPA ignored the role of supportive state regulatory frameworks in increasing state EE savings rates.

In addition to the issues related to how EPA assessed the reductions achievable through the Building Blocks and subsequently calculated the proposed state goals, EEI's comments address a range of compliance issues and concerns.

States need clarity on a range of other issues before beginning work on compliance plans. As a preliminary matter, **states need guidance as to how to account for the interstate impacts of renewable energy and end-use efficiency, so that they can develop plans that do not risk disapproval because they rely on reductions that have been double counted.** EPA proposes to allow states to use renewable energy generated in other states for compliance. While this

approach appropriately recognizes existing interstate markets for renewable energy credits, it places significant compliance burdens on states that are the source of renewable generation but were not, in the past, large consumers of this generation.

Multi-state planning would mitigate some double counting concerns. It also would mitigate some concerns about inefficient dispatch and siting that would arise from a patchwork of state plans, particularly when similar units in different states participate in the same power market, but face substantially different CO₂ costs. However, states may not be able to design multi-state plans in the limited amount of time between when the guidelines are finalized and compliance plans are due. **EPA should facilitate, incentivize and provide sufficient time for states to develop multi-state plans to mitigate possible double counting concerns.**

EPA proposes that a state only be allowed to include in its plan those CO₂ emission reductions that occur in the state as a result of demand-side energy efficiency programs and measures implemented in that state. Not only is this physically impossible, but it is conceptually at odds with EPA's general approach to EE measures. **EPA should allow states to include the full estimated benefits of in-state EE programs in state plans, regardless of whether a state imports or exports electricity.** Further, forcing states to discount EE reductions because of electricity imports may discourage states from using EE as a compliance tool, and EPA should not create disincentives that might prevent states from incorporating these measures in compliance plans.

EPA appropriately recognizes that states have the authority to include non-BSER measures in compliance plans. **The final guidelines should affirm the ability of states to include a wide range of non-BSER measures—both those identified by EPA in the guidelines and those not specifically included—in an approvable state compliance plan.** In particular, the final guidelines should affirm that states can include transmission and distribution efficiency improvements in compliance plans. These technologies can help increase reliability, resiliency and efficiency, all of which ultimately contribute to reducing CO₂ emissions.

To help states and electric utilities design compliance plans, EPA should provide greater clarity on a range of compliance issues. For example, EPA should take steps to ensure that New Source Review (NSR) concerns do not create disincentives or impede efforts to improve heat rates at existing coal-based units by clarifying that these actions do not trigger NSR. EPA should also provide clarity regarding accounting for emissions from biomass before states are required to submit compliance plans. Furthermore, states should be able to use new NGCCs to reduce total emissions, support integration of new renewable generation and meet future increases in demand. A state plan that relies on new NGCC units to achieve its emission rate goal should recognize the emissions from these units to avoid unintended environmental outcomes. Additionally, states with goals of less than 1,000 lb/MWh should be allowed to build new NGCCs to support integration of variable renewable resources or to serve load while preserving state discretion as to whether to include these new units in a state's compliance plan.

Other compliance issues that **EPA should provide clarity on in the final guidelines include broadly defining the types of “corrective measures” that states could include in compliance plans** to include methane reductions from natural gas distribution systems.

EPA also should affirm the importance of electrification in reducing CO₂ emissions from other sectors, and make clear that states will not be penalized under section 111(d) as a result of these efforts.

The final guidelines should facilitate the use of end-use efficiency measures for compliance by recognizing existing state evaluation, measurement and verification (EM&V) protocols for EE measures, allowing the use of gross energy savings, and allowing states to include new EE measures (such as codes and standards) in their compliance plans. Guidance on how states can incorporate distributed generation in compliance plans also needs to be provided. In addition, the guidelines should offer greater clarity regarding how obligations placed on EGU owners, electric utilities and others contained in state plans will be enforced.

The majority of EEI’s comments address the guidelines as they have been proposed by EPA, with the goal of creating a compliance framework that allows states and electric utilities to achieve emission reductions while also providing affordable and reliable electricity. The proposed guidelines, however, are predicated on an unprecedented and expansive approach to BSER that encompasses the potential to reduce emissions as a result of action at both affected EGUs and throughout the entire interconnected power system. The implications of this approach

for the power sector, the states and all other source categories regulated under section 111(d) are significant, and EPA's approach raises many legal issues and concerns.

B. The Final State Emission Rate Goals and Compliance Periods Must Consider and Accommodate the Operational Reliability Requirements of the Interconnected Power System.

As EPA notes, states and electric utilities are in the process of transitioning the generating fleet and the transmission system so that it is cleaner and more resilient. Achieving the interim and 2030 goals would accelerate this transition dramatically and require significant changes to the interconnected power system and the way that it operates. However, the proposed state goals and compliance period do not account for the complexity of power grid operations adequately, nor sufficiently address how the need to maintain reliability affects the pace and timing of implementing such changes.

The need to maintain operational reliability while undertaking significant changes to the way in which power is generated, transmitted and consumed has important implications for EPA's BSER determination, the computation of the state-specific emission rate goals and the achievement of the proposed interim average goals. It is essential that these changes be implemented in a way that maintains reliability for electricity customers.

While EPA does not have the expertise to assess fully the implications of the proposed guidelines on the interconnected power system, that does not mean that the Agency can ignore the complexity of the electric system when developing state-specific emission rate goals and compliance timelines. Rather, EPA should take into account information from experts in reliable system operations to develop achievable final goals and a workable compliance period that does

not jeopardize reliable electric service. However, all of the reliability studies and information needed to assess the significant changes that will be required to achieve the interim and 2030 goals will not be available before EPA finalizes the proposed guidelines or even before states are required to submit compliance plans for EPA approval. States, electric utilities, system operators and other regulators will need sufficient time to assess the changes that will be required to implement the state plans and will need the time required to make the system changes and develop the infrastructure needed to implement the state plans and maintain reliability. Going forward, EPA must be willing to allow states to address these changes by proposing revised compliance plans as necessary to meet the 2030 goals.

1. There are many elements to ensuring the reliable operation of the interconnected power system; resource adequacy is only one of them.

In the preamble, EPA undertakes an analysis of the electric system that fails to accurately and completely depict the complexity of operating the interconnected electric system. This is exemplified by EPA's repeated inaccurate assertion in the preamble and supporting Legal Memorandum, that electricity is "fungible." *See, e.g., 79 Fed. Reg.* at 34,880; Legal Memorandum at 44-45. In meeting customer demand, electrons and generation units are *not* fungible. While an end-use customer may be indifferent as to the source of the electrons consumed, the bulk power system is not.

When the North American Electric Reliability Corporation (NERC)—the entity charged by the Federal Energy Regulatory Commission (FERC) with ensuring, evaluating and improving the reliability of the bulk power system under the Federal Power Act (FPA)—prepares its required annual long-term reliability analysis, it looks at a range of "key reliability indicators, including peak demand, energy forecasts, resource adequacy, transmission development and changes in the

overall system characteristics and operating behavior.” *See* NERC, *2013 Long-Term Reliability Assessment*, at 1 (Dec. 2013) (2013 LTRA).³ EPA’s limited analysis focused primarily upon resource adequacy as measured by generation reserve margins and assumed that the state plan development process provides adequate opportunity to address other reliability issues. *See* Resource Adequacy and Reliability Analysis Technical Support Document (Resource Adequacy TSD). This clearly is not the case.

In order to understand how the proposed guidelines will change power system operations, it is important to first understand how the electric system operates. Specifically, it is critical to understand how reliable operation of the bulk power system is achieved and maintained both under normal and abnormal conditions. Because of the complexity of the interconnected power system, reliability is something that must be planned for, coordinated and constantly assessed and monitored.

a. Resource adequacy is just one of many dimensions that must be managed to ensure the reliability of the electric system.

At its most basic level, reliability is maintained when the demand for, and supply of, electricity are precisely matched (often referred to as “balancing”). As FERC staff explains:

[O]perators must plan and operate power plants and the transmission grid so that demand and supply exactly match, every moment of the day, every day of the year, in every location.

³ The 2013 LTRA is available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf.

See FERC, Office of Enforcement, *Energy Primer: An Overview of Energy Market Basics*, at 37 (July 2012) (FERC Primer).⁴

Providing reliable power is the electric industry's top priority mission, and getting electricity from generators to customers requires more than ensuring there is an adequate supply of power to meet demand. Because electricity, by its nature, moves only via the flow of current, the interconnected power system, which has been described as the largest and most complex machine in the world,⁵ is in a constant state of flux. The industry maintains the grid's physical and cyber security, reliability and robustness on a continual, minute-by-minute basis. For many years, the electric sector developed and operated under voluntary programs to assure reliability.⁶ Since the enactment of FPA section 205, the electric industry has transitioned successfully to a comprehensive set of mandatory, enforceable reliability standards for the bulk power system. Companies now may be assessed penalties of up to \$1 million per day per violation under this system.

Consistent with the mandatory, enforceable reliability standards which ensure that power can be delivered to customers reliably, other system requirements—beyond ensuring that there is sufficient electricity to meet demand—must be respected and addressed. These system

⁴ The FERC Primer is available at <http://www.ferc.gov/market-oversight/guide/energy-primer.pdf>.

⁵ See Phillip F. Schewe, *The Grid: A Journey Through the Heart of Our Electrified World* (Joseph Henry Press 2006).

⁶ Federal Power Commission, *Report to the President by the Federal Power Commission on the Power Failure in the Northeastern United States and the Province of Ontario on November 9-10, 1965* (Dec. 6, 1965), http://blackout.gmu.edu/archive/pdf/fpc_65.pdf.

requirements cannot be afterthoughts. The interconnected system must be designed to accommodate these requirements.

First, load and generation resources—which can include both generation and demand-side resources—must be balanced continuously. This constant balancing includes not only having the megaWatts (MW) of energy that are needed to meet peak demand, but also the mix of generation types needed to maintain system reliability as not all resources provide the same services to the electric grid. Having an adequate amount of total resources (resource adequacy) “does not necessarily equate to having the right type of resources with the right functional capabilities to maintain reliability.” NERC, *Essential Reliability Services Task Force, A Concept Paper on Essential Reliability Services that Characterize Bulk Power System Reliability*, at 13 (Oct. 2014) (ERS Report).⁷

In addition to those resources needed to serve actual customer demand, adequate **operating reserves** must be available throughout the system to connect instantaneously or on very short notice in the event a generator goes down or other system disruptions occur. There also must be adequate **ramping capability**—the ability to increase or decrease generation over a period of time in response to major changes in demand—to follow variable generation resources or in emergencies. Ramping capabilities and reserve requirements are heavily intertwined with the dispatch control of the power system. These requirements ensure that sudden changes in load and the variability of power supply can be met.

⁷ The ERS Report is available at:
<http://www.nerc.com/comm/Other/essntlrbltysrvestskfrDL/ERSTF%20Concept%20Paper.pdf>.

In addition to maintaining grid stability, resources must be able to **maintain frequency control** within tight tolerances to maintain the target 60 Hz frequency. Frequency is an indication of the real-time balancing between supply and demand. Large nuclear and fossil synchronous generating units with rotating mass traditionally have provided **inertia** (stored rotating energy), which is an important reliability characteristic supporting frequency control by arresting frequency decline if there is an unexpected loss of a generating unit, giving system operators time to restore frequency to the target operating level. *See ERS Report at 8-9.*

Voltage control is needed to maintain voltages in a secure, stable range throughout the system and to maintain this support in the event of voltage disturbance. Voltage is the force needed to move electrons in the transmission system, and its constant changes over time must be managed. Voltage support is a very local service and cannot be transmitted far from the source that provides it. This requires complex considerations to assure **reactive power/power factor control and stability**. Reactive power requirements can change rapidly. *See ERS Report at 9-10.*

Balancing demand and supply not only must ensure consistency with all of these system constraints, but also must ensure that the amounts of electricity placed on the transmission and distribution system do not overload those systems. There are **thermal (heating) limits** that must be respected; otherwise transmission and distribution lines may be overloaded and damaged. Heat conduction (how heat is dispersed through equipment) also is affected by temperature, wind and other factors. In extreme circumstances, an imbalance could require generation resources to disconnect from the system.

“[T]ransmission flows must be monitored to ensure that they stay within voltage and reliability limits.” *See* FERC Primer at 58. This means that the location of particular generators, relative to other generators and available transmission capacity, is an important factor in determining which units can be dispatched because location affects transmission flows and voltage limits. To support the moment-by-moment balancing of electricity demand and supply, FERC regulations require the provision of adequate transmission service.⁸ Public utilities have tariffs on file pursuant to these regulations. FERC audits these transmission service tariffs and has imposed penalties for deviations from tariff requirements.

Adequate transmission and generation infrastructure, as well as other essential services, are critical for the reliable operation of the integrated grid. System operators do not have complete flexibility in the procurement of these services, many of which are often referred to as “**ancillary services**,” as they often need to be provided by units in specific locations due to the physics of electricity. Reactive power, for example, does not “travel” over distances and is,

⁸ *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities: Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 *Fed. Reg.* 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh’g*, Order No. 888-A, 62 *Fed. Reg.* 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh’g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh’g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff’d in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff’d sub nom. New York v. FERC*, 535 U.S. 1 (2002) (Order No. 888); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 *Fed. Reg.* 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh’g*, Order No. 890-A, 73 *Fed. Reg.* 2,984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh’g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh’g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009) (Order No. 890); *Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh’g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh’g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff’d*, *So. Carolina Pub. Serv. Auth. v. FERC*, No. 12-1232 (D.C. Cir. Aug. 15, 2014) (Order No. 1000).

therefore, a “local” requirement that can be provided only by a few resources when needed. *See* ERS Report at 11. FERC recognizes the following as ancillary services: scheduling, system control and dispatch; reactive supply and voltage control from generation service; regulation and frequency response service; generation and energy imbalance service; operating reserve – synchronized reserve service; and operating reserve – supplemental reserve service. *See* Order Nos. 888, 890. Under FPA sections 205 and 206, all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce are required to take transmission service, including these ancillary services, for wholesale sales and purchases of electric energy under open access tariffs.⁹ Ancillary services, in addition to capacity and energy, are necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system. Ancillary services are so essential that FERC also requires that transmission service providers—absent third-party service—provide them to ensure the reliable delivery of electricity.

It is important to note that all generating resources do not provide the same services to the electric grid and that all electrons may not be able to serve all customers due to electric transmission or other constraints. Different sources are needed to ensure that electrons actually reach end-users. While all generating units produce electricity, some types of units only supply energy, others supply critical grid services (balancing, back-up and ancillary services like voltage

⁹ Black start service, an additional ancillary service, is a voluntary service that can be provided by some, but not all, generation resources. These generating units have the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the electric grid. Hydroelectric facilities and diesel generators have this capability. These are the first facilities to be started up in the event of a system collapse or blackout to restore power flows in the grid. *See* FERC Primer at 37.

and frequency control) that are needed to ensure the stability of the transmission system and other types provide capacity to ensure resource adequacy and reliability. Renewable generation units can provide electrons, but are limited in their ability to provide grid or peak period capacity services. Retirement of base load coal-based units diminishes the pool of resources that are able to provide these other services to the grid and places increased responsibility on natural gas-based resources to serve as base load units, back up renewable resources, provide ramping capability and provide ancillary services to the grid.

Given the system requirements that must be met in order to maintain reliability, even the seemingly simple decision to close a single fossil base load unit and replace it with a renewable generator requires consideration of, at least, the availability of sufficient generation to meet demand, the need for ramping and back-up power, the availability of natural gas supplies and the infrastructure to deliver it, the impact on the transmission system and the need to maintain inertia, frequency and voltage control. Choosing to increase the generation at an existing unit that already is interconnected to the transmission system requires consideration of similar issues. Managing these considerations requires a significant amount of rigorous and time-intensive study and coordination.¹⁰

¹⁰ Any addition or change to the transmission system has to go through the interconnection study and analysis process. This is true whether the change is to the capacity of an existing generator or a new generator is proposed. The purpose of these studies is to assess the impact of a new generating unit (or increase in generation from an existing unit) on the existing transmission system. The required studies consist of thermal analyses, stability studies and assessments of possible faults in the system that could result in cascading failure of the transmission system. No generator can be attached to the transmission network unless and until these studies show that the system can withstand the injection of energy at that particular point.

However, these studies only determine whether the system will be harmed by adding the generator or increasing capacity. An additional study, generally referred to as a “simultaneous

b. There are many entities charged with managing the various elements critical to maintaining the reliability of the electric system.

There are many entities charged with ensuring that all system requirements are met, such that reliable electricity is provided to customers. FERC is the federal authority ultimately responsible for maintaining the reliability of the interstate electric transmission grid under the FPA. NERC is the entity charged by FERC with developing reliability standards, overseeing and evaluating system reliability. But, in general and at the practical level, it is the system operator's responsibility to ensure that the system operates reliably. The system operator in bilateral markets is the electric utility. In areas in which electric utilities have joined regional transmission organizations (RTOs) or independent system operators (ISOs), the RTO or ISO has functional responsibilities for system operations.

The electric grid in the continental U.S. is electrically synchronized in three interconnections—Eastern, Western and the Electric Reliability Council of Texas (ERCOT). The Eastern Interconnection is comprised of numerous actors, including: federal power marketing agencies (PMAs); the Tennessee Valley Authority (TVA); public power utilities; transmission-only utilities; and vertically-integrated investor-owned utilities. Many of these entities are members of one or more of five separate RTOs/ISOs.¹¹ The Western Interconnection is comprised of: federal PMAs; public power entities; and vertically-integrated utilities, including utilities that are members of the California ISO. ERCOT is comprised of investor-owned and public power

feasibility study,” must be done to determine whether the electricity actually can be moved from the point of production to other points on the transmission system. The results of this study determine whether transmission upgrades or expansions are needed to accommodate the increased generation. MISO's Generator Interconnection Procedures, for example, describe these required studies in more detail. *See* MISO Tariff, Attachment X, section 2.1 (a).

¹¹ These are: ISO NE, PJM, MISO, SPP and NYISO.

utilities that either own transmission and distribution facilities or provide deregulated generation and retail services.

Some of the principal functions of the system operator include provision of transmission service and transmission planning to ensure the continual reliability of the grid. *See* Order No. 2000.

They also make dispatch decisions by taking into consideration least-cost generation, numerous reliability requirements and any existing transmission constraints to determine which EGUs run to meet demand or provide other grid reliability services (this process is known as “security-constrained economic dispatch”). Another key function of system operators is to manage congestion. In RTOs and ISOs this is addressed through competitive markets, including day ahead and real-time energy markets, capacity markets and other markets to address energy imbalances and provide other ancillary services. The market rules and structures are subject to FERC jurisdiction to ensure that they produce “just and reasonable rates,” as required by FPA section 205(a).

In competitive markets, each RTO and ISO has created markets to replicate the revenue streams for energy, capacity and ancillary services provided in vertically integrated markets that have regulated rates of return. Generators in RTO/ISO markets rely on price signals from these markets to make investment decisions regarding which generating resources are needed and should be added to the system. Significant market changes impact these price signals—which could have reliability and resource adequacy implications if the price signals do not incent construction of needed new generation and infrastructure.

2. The proposed state emission rate goals and compliance periods do not reflect the reliability implications of changing the interconnected power system by implementing the BSER Building Blocks.

In proposing the state emission rate goals and compliance periods, EPA did not assess the interconnected power system's reliability requirements. EPA also did not assess the effects each Building Block will have on the other Building Blocks or on the bulk power system when simultaneously undertaken at the levels EPA believes are achievable. Because the goals and compliance periods proposed do not reflect the reliability implications of the changes to the interconnected power system that will be required to implement the BSER Building Blocks, they do not fully depict the changes the system may have to implement, the costs that will be incurred or the time that these changes will take.

a. In setting the state-specific emission rate standards, EPA did not consider the impacts of the BSER Building Blocks on each other in the context of the integrated power system.

As a preliminary matter, EPA cannot assess the reduction potential of each Building Block individually and then add their total generation and emission reductions together to establish the state-specific emission rate goals. This ignores the fact that the actions and measures under each Building Block will impact each other when implemented simultaneously because they are not independent, but part of the integrated power system.¹²

For example, the addition of variable wind and solar resources likely will require increased use of natural gas units for back-up and ramping, which could be incompatible with EPA's proposed 70-percent utilization rate for existing NGCC units. These units cannot both run at high utilization rates and simultaneously be available to support variable renewable generation.

¹² These issues are discussed fully *infra*, section II, which addresses the assumptions and analysis that underpin EPA's proposed state-specific emission rate goals.

Further, increased utilization of existing NGCC units is intended to reduce the utilization and increase the cycling (turning on and off) of existing coal-based units, which will undermine efforts to improve the heat rates of existing coal-based units. These units are most efficient when they run consistently at high capacity factors. Therefore, reduced load and operations of coal-based units will erode any efficiency gains that might be made through heat rate improvements. The final goals should reflect such interactions and any limitations they place on achieving the levels of reductions the Agency projects could be achieved by any single Building Block.

b. Reliably implementing state compliance plans that incorporate the BSER Building Blocks will require changes in the way that the interconnected power system currently is designed and operated; these changes cannot be accomplished by 2020.

EPA assumes that the proposed guidelines provide sufficient time and flexibility for states to manage the accelerated transition of the existing generating fleet that the rules envision. *See, e.g., 79 Fed. Reg. at 34,904; see also* Resource Adequacy TSD at 1. This assumption is predicated on the idea that implementing the proposed Building Blocks¹³ will not require changes to the existing interconnected power system. As noted above, this is simply not true. A change to any part of the interconnected power system—even one that appears relatively minor, such as increasing the generation produced by an existing unit—requires an analysis of the potential impacts on the rest of the system. The multiple, larger changes proposed by EPA

¹³ EPA notes that states are not limited to the four Building Blocks when designing compliance plans aimed at achieving the emission rate goals. As a practical matter, and as discussed in greater detail *infra*, section III, state plans largely will rely on the four Building Blocks because there are few other options to achieve the same magnitude of reductions in states' average emission rates. States may be able to vary the level of reductions from any particular Building Block to some degree, relative to the assumptions EPA made in setting the state goal rates, but few states will be able to forego completely any one of the Building Blocks and still demonstrate compliance with the 2030 emission rate goal.

certainly require such analysis under NERC's reliability standards.¹⁴ In addition to new resources, changes in how the generation fleet is dispatched may cause significant changes in how power flows across the grid. To meet NERC standards, new transmission infrastructure may be required, which is not possible by 2020 because of the numerous transmission studies, planning and construction required to reliably integrate the changed system conditions.

NERC addressed the need for such studies and the potential for major system modifications in its 2013 Long-Term Reliability Assessment.¹⁵ NERC assessed the system implications for the key reductions and measures that comprise EPA's BSER determination and likely compliance tools. The following discussion highlights some of the key NERC findings on the required system changes and analysis necessary to achieve CO₂ emission reductions, all of which will require changes to the interconnected power system that must be planned and managed closely to ensure continued reliability:

Fossil-Based Retirements and Coordination of Outages for Environmental Control

Retrofits. The potential reliability implications of closing a coal-based unit are varied. Retiring a coal-based steam electric turbine reduces the ability to arrest and stabilize system frequency following a grid disturbance or the loss of a large generator. *See* 2013 LTRA at 31-32. Replacing the lost generation with renewable resources is possible, but these may not be able to offer inertia or frequency response. Wind could be used to replace some of these requirements, but must be specifically designed to do so. *See id.* Replacing the coal-based units with increased generation from an existing NGCC unit may be feasible, but this requires other assessments to

¹⁴ The Southwest Power Pool (SPP) released a reliability assessment of the proposed guidelines, which concluded, among other things, that new generation and transmission expansion would be necessary to maintain reliability while achieving the proposed emission rate goals. *See* SPP, Reliability Assessment of the EPA's Proposed Clean Power Plan at 7 (Oct. 8, 2014), <http://www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf>. MISO also is analyzing the impact of the proposed guidelines will file comments in Docket No. EPA-HQ-OAR-2013-0602.

¹⁵ NERC engaged in similar analyses and reached similar conclusions in the 2014 LTRA, http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf.

determine if the transmission system can accept this increased generation or if transmission or interconnection modifications first will need to be made. *See id.* at 36.

Increased Dependence on Natural Gas for Electric Power. NERC has noted that “[a] growing dependence on natural gas-based generation can increase [bulk power system] exposure to disruptions in fuel supply, transportation, and delivery.” *Id.* at 35. Substantial investments in bulk power system and gas infrastructure may be needed to ensure that the requisite volume of gas can reach new and existing gas-based units. *See* NERC, *Reliability Impacts of Climate Change Initiatives: Technology Assessment and Scenario Development*, at 53 (July 2010) (Technology Assessment).¹⁶ NERC also found that “interconnecting these new resources will require new transmission” and the transmission system may need enhancements to provide reactive and voltage support, address thermal constraints, and provide for system stability. Long lead times for new rights-of-way for additions and transmission enhancement create timing issues beyond those required for generation.” *See* 2013 LTRA at 36.

Continued and Accelerated Integration of Renewable Generation. Quickly integrating an increasing amount of variable renewable generation requires electric utilities, states and system planners to consider a variety of factors. “Accommodating higher levels of variable resources requires cooperation and coordination...especially between [bulk power system and non-bulk power system] entities. Frequency stability, frequency response, energy imbalance, and increased and dynamic transfers must be addressed at all levels.” *Id.* at 22. NERC particularly noted the importance of ensuring that increased amounts of solar photovoltaic generation do not lead to decreased system inertia and frequency response capabilities that are critical for maintaining reliability. *See id.* Voltage support concerns also must be addressed, given the long distances between some renewable generators and the point of interconnection with the transmission system. *See id.* at 24. Transmission expansion will be a key consideration. As NERC has noted, “[t]ransmission system expansion is vital for unlocking the capacity available from variable generation, and it can be used as a tool to reduce overall variability across a broader area.” *Id.* at 25. “The addition of a significant amount of variable generation to the [bulk power system] changes the way that transmission and resource planners develop their future systems to maintain reliability.” *Id.* at 24.

Increased Use of Demand-Side Management. NERC concludes that increased use of demand-side management (DSM), including energy efficiency (EE), can help to offset future resource needs, but creates additional uncertainty for system planners. *See generally* 2013 LTRA at 39-41. In order for electric utilities, states and other regulators to fully realize the potential benefits of increased DSM and EE measures, there must be close coordination between entities responsible for DSM and EE to ensure appropriate capacity values are estimated. Further, not all demand resources have the same reliability benefits. Assuring adequate measurement and verification of the load response, which will require advanced metering, load curtailment technologies and two-way customer communications, will be key. *See* Technology Assessment at 44-45.

¹⁶ This report can be found at http://www.nerc.com/files/RICCI_2010.pdf.

Nuclear Generation Retirements and/or Long-Term Outages. NERC concludes that nuclear generation not only provides a significant amount of generation, but provides important reliability services (inertia and voltage support) that contribute to the stability and integrity of the system and that widespread retirements or long-term outages could have significant impacts on the bulk power system. *See generally* 2013 LTRA at 42-44.

NERC affirmed that the proposed guidelines will require major changes to the way the interconnected power system is planned and operated in order to ensure reliability while achieving emission reductions in its recent Initial Reliability Review of the proposed guidelines.¹⁷ NERC stated that the proposed guidelines “introduce[] potential reliability concerns that are more impactful than prior environmental compliance programs due to the extensive impact to fossil-fired generation.” Initial Reliability Review at 17. In particular, NERC noted that the proposed guidelines do not recognize the need to expand and enhance the transmission grid and that the guidelines do not address grid reliability issues associated with increased variable resources and retirement of fossil-based generation:

Conventional generation (e.g., steam and hydro), with large rotating mass, has inherent operating characteristics, or ERS, needed to reliably operate the BPS. These services include providing frequency and voltage support, operating reserves, ramping capability, and disturbance performance. Conventional generators are able to respond automatically to frequency changes and historically have provided most of the power system’s essential support services. As variable resources increase, system planners must ensure the future generation and transmission system can maintain essential services that are needed for reliability.

Initial Reliability Review at 13.

Accordingly, “specific transmission and resource adequacy assessments—including resulting reliability impacts—will be essential for supporting the development of [state plans] that are

¹⁷ See NERC, *Potential Reliability Impacts of EPA’s Proposed Clean Power Plan: Initial Reliability Review* (Nov. 2014). The Initial Reliability Review is attached as Appendix A.

aligned with system reliability needs.” *Id.* at 4. Given the interconnected nature of the system, specific reliability impacts and necessary system changes cannot be assessed and coordinated until after all state compliance plans are finalized and approved, which will not be until 2017 at the earliest. As a practical matter, this schedule does not allow adequate time for the needed reliability assessments and system changes to be accomplished before 2020. *See* Initial Reliability Review at 10, 27. The studies themselves can take several years to complete.

Further, once the required studies are completed, actually building new generation, new natural gas delivery infrastructure and new transmission lines can also take years to complete, especially when involving rights-of-way crossing federal or tribal lands. As the Department of Energy (DOE) has recognized,

Infrastructure projects —such as high voltage, long distance, electric transmission facilities —often involve multiple Federal, State, local and Tribal authorizations and are subject to a wide array of processes and procedural requirements in order to obtain all necessary permits and other authorizations. Delays in securing required statutory reviews, permits, and consultations can threaten the completion projects of national and regional significance.

DOE, Rapid Response Team for Transmission (RRTT),¹⁸ *Request for Information*, Docket No. RRTT-IR-01, 77 *Fed. Reg.* 11,517 (Feb. 27, 2012).

¹⁸ The RRTT was created in response to a Presidential Memorandum recognizing the critical need to expedite the review and permitting of major electric transmission infrastructure projects. *See* Presidential Memorandum, *Speeding Infrastructure Development through More Efficiency and Effective Permitting and Environmental Review* (Aug. 31, 2011). The RRTT recognized that “[a]t least three problems may arise when trying to develop this type of infrastructure: (1) Non-synchronous evaluations by all governmental entities with jurisdiction; (2) uncertainty about whether all necessary permits and approvals will be received; and (3) significantly different development times for generation and transmission.”

However, EPA does not propose to wait until these studies are complete or until needed system changes are effectuated to finalize the proposed guidelines or require states to submit compliance plans. Therefore, the final proposed section 111(d) guidelines can and should recognize the complexity of what the Agency is asking states, electric utilities, system operators and other regulators to do in order to achieve the 2030 goals. To the extent possible, EPA's final state goals should reflect the operational reliability needs of the interconnected power system as they currently are understood. In addition, the final guidelines should include a compliance timeline that provides states with sufficient time to analyze the impacts of their proposed plans on the interconnected power system and ensure that the power sector has sufficient time to implement the required changes to the entire interconnected power system.

Further, although EPA has not yet considered how the proposed Building Blocks will cumulatively affect the interconnected power system, the Agency should be open to modifying the 2030 state-specific emission rate goals in the final guidelines to recognize that the Building Blocks affect each other in the context of the interconnected power system.

II. EPA Must Address A Range of Compliance Issues So That States Are Able To Craft and Submit for EPA Approval Plans That Demonstrate How They Will Achieve The Proposed Goals.

The final guidelines will set the emission rate goals for the states, but how these goals will be achieved depends on the reductions, actions and measures that states include in the compliance plans that will be submitted to EPA for review and approval. As EPA has recognized, states need the flexibility to design plans that reflect a range of state-specific circumstances. *See* 79 *Fed. Reg.* at 34,837. Importantly, states need real flexibility in order to be able to choose the most cost-effective reductions, as determined by the states, to ensure that electricity remains

affordable for consumers. Allowing each state to choose its individual glide path will allow them to use the actions that work best for them to reliably and cost-effectively reduce carbon emissions in their state. States also need clarity on a range of topics so that they can craft compliance plans that will be approvable.

Specifically, states need the flexibility to design emission rate reduction glide paths that reflect the states' determination of the best way to achieve the 2030 goals while maintaining reliability and protecting the affordability of electricity. However, the current design of the interim average compliance period forces many states to achieve the majority of the required reductions by 2020, if not before. Not only is this not practically achievable, it deprives states of the flexibility to design their own compliance plans or choose the pace of reductions to respect state-specific conditions and circumstances. Further, as discussed at length in the beginning of these comments, implementing actions and measures that comprise the four BSER Building Blocks—which also will comprise the centerpiece of most states' compliance plans¹⁹—will require states, electric utilities and other regulators to assess the impacts of the Building Blocks on the interconnected power system. The complex analysis required will take time, as will making the changes necessary to accommodate the dramatic shift in how electricity is generated and delivered as envisioned by the proposed guidelines. The final guidelines should ensure that adequate time is available, both to design compliance plans and to implement them. The final

¹⁹ As discussed elsewhere in these comments, states are not required to implement the Building Blocks exactly as they were used by EPA to set the state-specific emission rate standards. However, as a practical matter, there are limited alternative measures that would achieve the same magnitude of reductions such that it is unlikely that a state could completely forego the use of a particular Building Block. Non-BSER measures will be important flexibility tools that allow states to choose to deviate, where necessary, from EPA's assumed level of reductions that can be accomplished by the Building Blocks, but they will not be substitutes for any of the Building Blocks.

guidelines should clearly authorize this range of options, so that states have the confidence to pursue them, pending final EPA approval of compliance plans.

A. EPA Should Eliminate the Interim Compliance Goal and Approve State Plans that Achieve the 2030 Goals through Reasonable Emission Reduction Glide Paths and Milestones that Assure Reliability and Protect Customers.

For each state, EPA proposes both an interim and final emission rate goal. *See id.* at 34,895 & Table 8. The interim goal is measured via a ten-year averaging period that starts in 2020. *See id.* at 34,851. EPA asserts that the proposed guidelines generally provide states with sufficient time and flexibility to design “practical” plans that achieve reductions in a “reasonable cost way.” *See id.* at 34,387. EPA specifically notes that the interim plan period “increases state flexibility to choose among alternative potential plan measures.” *Id.* at 34,897. The interim compliance period may be well intended, but its design—particularly the interim 10-year average goal—actually serves to limit state flexibility. In order to satisfy the 10-year average goal, a significant number of states need to achieve reductions before the start of the interim compliance period in 2020.²⁰ Moreover, many states must achieve over 50 percent or more of their 2030 emission goals by 2020; and eleven states—including Arizona, Arkansas, Florida and Minnesota—must achieve over 75 percent of their 2030 goals by 2020. This effectively turns the 2030 goal into a 2020 goal for these states. Thus, contrary to EPA’s stated intent of providing states flexibility in setting 2030 emission goals, the interim compliance average goal creates more compliance challenges than it solves. Further, as NERC notes, this “proposed timeline does not provide enough time to develop sufficient resources to ensure continued reliable operation of the electric grid by 2020” and that attempting to implement the proposed guidelines without addressing

²⁰ The state goals, in part, are predicated on states taking action before 2020. For example, EPA identifies individual states that need to begin implementing programs in 2017 for expanded renewable generation and additional energy efficiency measures if the emissions reductions EPA identifies in Building Blocks 3 and 4 are to be realized.

reliability considerations “would increase the use of controlled load shedding and potential for wide-scale, uncontrolled outages.” Initial Reliability Review at 22.

Eliminating the interim compliance goal and allowing states to determine their own reduction glide paths and milestones to achieve the 2030 goals—subject to EPA approval and annual compliance reporting—would provide states with real flexibility in designing state plans while providing real, verifiable emissions reductions. Eliminating the interim targets does not mean that no actions will be taken by each state to reduce carbon emissions before 2030. On the contrary, each state would have the flexibility to determine the most cost effective and reliable way to achieve the 2030 emission goals while outlining the meaningful reductions expected in each individual state plan’s glide path. This approach would allow states sufficient flexibility to determine not only which actions and measures to pursue to reduce emission rates, but also to choose a reasonable schedule for implementing those measures consistent with providing safe, reliable, affordable and environmentally responsible power to customers. Importantly, this would provide states and utilities additional time to complete needed infrastructure development (including expansions and upgrades of both electric and natural gas transmission systems) to manage changes in dispatch between coal-based and natural gas-based units and increase deployment of renewable generation and energy efficiency programs. It also would provide states, electric utilities and other regulators time to assess the significant changes to the interconnected power system that will be required to achieve the 2030 goals, discussed in more detail in section I.B., above, while respecting system requirements necessary to maintain reliability. States would also be able to better manage the impact of the program on customer

rates. Real flexibility helps states achieve reductions while ensuring the continued provision of affordable and reliable electric power.

EPA should allow states to adopt an approach in their state plans, based on objective criteria that deliver the desired reductions in a manner consistent with consideration of the remaining useful life of existing generating resources, grid reliability and customer cost minimization. Unless EPA finds that the states are not properly demonstrating reasonable progress toward attainment of the goal, no need for strict interim deadlines exists.

This approach is also consistent with EPA's stated goals for the proposed guidelines. In the NODA, EPA notes that the Agency is "interested in considering additional stakeholder ideas, such as those regarding the 2020-2029 glide path, to ensure that the overall framework includes sufficient flexibility, particularly with respect to timing of and strategies for reducing emissions from affected units so that states can develop cost-effective strategies, and states, utilities, grid operators and others can readily respond to unexpected challenges or demand on the energy system, such as severe weather." 79 *Fed. Reg.* at 64,545.

Consistent with the state plan requirements that EPA has proposed, states would be required to demonstrate reasonable and verifiable progress toward the 2030 goal and could not delay taking action to reduce emissions. EPA's proposed guidelines already would require that states submit—and that EPA approve—plans that clearly set forth how states would achieve the 2030 goal. Once approved by EPA, a state's plan, including the emission reduction glide path, would become enforceable. States would demonstrate progress towards the 2030 goal consistent with

their projected emission reduction glide path through the annual reporting of emission performance to EPA, taking corrective measures if needed to achieve the 2030 emission levels. Ultimately, if states are unable to show reasonable progress toward the 2030 goal, EPA, as set forth in the CAA section 111(d), still would have the authority to call for a state to correct its plan or to prescribe a federal plan. Using the proposed approach to state plans, EPA can ensure that the 2030 goals are achieved while allowing states sufficient flexibility to design their own compliance glide path.

To promote maximum state flexibility in the design of approvable compliance plans and to enable states to take into account changed circumstances, such as improvements in clean energy and other technologies, the final guidelines should clarify that states can modify plans, subject to EPA approval, to address changing circumstances. The final guidelines also should affirm that EPA will approve compliance plans that satisfy the requirements for such plans. Finally, the guidelines should recognize a range of potentially approvable options for defining state emission glide paths that would be unique to the specific circumstances within a state or multi-state program and, in particular, should support the use of existing programs and market mechanisms.

1. The proposed guidelines, including the proposed interim average emission rate goal, create significant near-term compliance challenges and limit state flexibility.

The proposed interim average compliance period and goal would create unnecessary compliance challenges, limit state flexibility in designing compliance plans and impose unnecessary additional costs on electric customers.

a. The operational realities of the interconnected power system are inconsistent with a proposed interim compliance period beginning in 2020.

For states to comply with EPA's proposed 10-year average goal, a majority of states must achieve the majority of emission reductions by 2020. As noted in section I of these comments, achieving the 2030 goals while ensuring the continued reliable operation of the interconnected power system would require significant changes to the system and the way that it operates. These changes in the manner in which power is generated, transmitted and consumed must be done in a way that maintains operational reliability and provides consumers with least-cost power. This cannot even potentially be accomplished without eliminating the interim goals and allowing states to establish an individualized glide path to 2030 compliance.

For states and utilities to achieve the proposed 2030 goals, new generation and upgraded and expanded transmission and distribution facilities will be needed. Some of these will be required to meet the goals; others will be required to ensure that system reliability requirements are met. Any new or upgraded infrastructure elements will require significant time, capital and planning by states, utilities, system operators, permitting agencies and other state and federal regulators in order to integrate them into the interconnected system. In order to make these changes, system operators and their stakeholders must conduct specific reliability impact assessments and necessary system changes. As noted earlier, given EPA's rulemaking timeline, this schedule does not allow adequate time for the needed reliability assessments and system changes to be accomplished before 2020. Building new generation, new gas delivery infrastructure and new transmission lines—which take years to plan and execute—will also necessarily occur after 2020. *See Initial Reliability Review at 10, 20.*

b. States cannot increase utilization of existing NGCCs units to 70 percent by 2020.

The proposed interim average goal assumes that the full 70 percent utilization of existing NGCC units has occurred by 2020 and is held constant through the 10-year interim compliance period. *See* Goal Computation TSD at 10-11. Unlike RE and EE measures, increased NGCC utilization is not phased in over the interim average compliance period; therefore, in order to meet the proposed goals, states *must* achieve the full magnitude of the reductions associated with this significant dispatch change starting in 2020. *See id.* at 18. For states in which increased utilization of existing NGCC units drives the stringency of the emission rate goals, this means that the majority of compliance must be achieved *before* 2020. EPA asserts that the interim period is a “10-year ramp-up period,” 79 *Fed. Reg.* at 34,906, but instead of allowing states to phase-in reductions, the 2020 interim average goals create an emission reduction ‘cliff’ for many states.

Requiring that all changes in dispatch be achieved before the interim compliance period begins eliminates any flexibility states have to determine how quickly to make these changes or to assess and address the implications for the interconnected power system. It also reflects the fact that the proposed guidelines do not acknowledge or consider how the interconnected power system works. For example, the Director of the Arizona DEQ has noted that, “the proposed goals for Arizona were set based upon an EPA assumption that all of our existing coal-fired power generation could be immediately transferred to existing natural gas-fired power plants by 2020.”²¹ Arizona, therefore, is required to achieve at least 75 percent of its final 2030 goal by 2020. According to the DEQ, Arizona’s only option to achieve this level of reductions by 2020 is through switching from coal to natural gas. *See id.* Even if Arizona has an approved state

²¹ *State Perspectives, supra*, n.46.

plan by 2017, this is an unprecedented reductions requirement that must be achieved in, at most, a few short years.

Moreover, it is not clear that the dramatic increase in utilization of existing NGCC units by 2020 envisioned by EPA can be achieved. As discussed in section II.B., above, EPA incorrectly assumes that current natural gas infrastructure is sufficient to support this dramatic increase in the utilization of existing NGCC units.²² Under EPA's proposed guidelines, existing pipeline infrastructure would need to be expanded in a short time frame. However, it can take three to six years to permit and build new pipelines. *See* Initial Reliability Review at 10. Although the FERC is the lead federal agency for approving interstate natural gas pipelines, under the FPA these new pipelines often require approvals under other statutes from other federal, state and local agencies.²³ In order to take advantage of the abundance of shale gas resources, new pipelines will be needed to transport these natural gas supplies to regions of the country that propose to build new, lower-emitting NGCC units. If the pipelines will cross federally-owned

²² There is a seasonal divide in the use of existing natural gas pipeline capacity that may exacerbate pipeline infrastructure issues in some regions. For instance, in certain regions, many pipelines originally were developed in coordination with local gas distribution companies for the purpose of delivering gas to residential and commercial customers, generally for heating or industrial purposes. A significant portion of natural gas pipeline capacity in those regions is therefore utilized during winter months to transport gas for home heating purposes, rather than for power generation purposes. Many natural gas units provide peaking services primarily in summer months due to the abundance of available capacity; however, they typically provide fewer services in winter months, in part, because the pipelines they rely upon for natural gas supply are capacity constrained through the delivery of natural gas for home heating purposes.

²³ *See* GAO, *supra*, n.47. The GAO report lists other applicable statutes to include the National Environmental Policy Act, the Clean Water Act, the Endangered Species Act, the National Historic Preservation Act, the Rivers and Harbors Act of 1899, the Clean Air Act, the Migratory Bird Treaty Act, the Safe Drinking Water Act and the Wilderness Act. Permitting agencies include FERC, EPA, U.S. Corps of Engineers, Bureau of Indian Affairs, Bureau of Land Management, Department of Wildlife and Fisheries, Forest Service, DEQ and a host of other federal, state and local agencies as well as tribal and local governments.

lands, approval of permanent rights-of-way from federal land managers must be obtained.

Because there is no streamlined process for obtaining such federal approvals, their approval can take years, which could impede the ability to expand the network of natural gas pipelines to deliver gas for power generation.

Further, increasing generation from existing NGCC units also may require electric transmission upgrades and expansions. However, as NERC has noted, a transmission project can take 10 or more years to complete, from project identification to final certification and energization. *See* Initial Reliability Review at 20. It may take even longer if a project crosses federal or tribal lands. These infrastructure constraints will challenge states' ability to achieve significant changes in dispatch before—and even after—2020. Recognizing infrastructure challenges and the need to make investments, EPA provides some time for other reductions measures, namely RE and EE to ramp up,²⁴ but provides no such flexibility for equally important changes in dispatch.

c. The interim compliance average period deprives states of choosing which reduction actions and measures to pursue and how quickly to implement them, with negative consequences for costs to customers.

EPA notes that “while states must begin to make reductions by 2020, full compliance with the CO₂ performance level in the state plan must be achieved by no later than 2030.” 79 *Fed. Reg.* at 34,838. Many states will have few options to start making reductions by 2020, which limits their ability to choose the reductions actions and measures that best reflect their specific circumstances and to implement them in a way that minimizes costs to customers.

²⁴ But, EPA assumes that these measures will start ramping up in 2017, before state plans may have been approved. *See* 79 *Fed. Reg.* at 34,867.

For example, Ameren, which serves Missouri, among other states, has a plan that can achieve the President's goal, of carbon emission reductions as outlined in the 2030 targets, by 2035. This plan has been submitted to the Missouri PSC as part of an integrated resource planning process calls for meaningful carbon emissions starting in 2022. The plan includes retirement of coal plants at the end of their useful lives, including a large coal plant in 2022, expansion of renewable generation and/or nuclear, adding an additional NGCC unit and a significant EE program. Under the defined rate based interim targets included in the proposed rule, the only reliable but costly way to demonstrate progress toward achieving the interim average goal—which, for Missouri, is 62 percent of its 2030 goals—is to accelerate the NGCC capacity by 15 years to 2020 and double that capacity to 1200 MW. This new gas-based generation is not needed to serve Ameren's customers; it will only displace coal generation in order to meet the interim rate based goals. Ameren will also be required to accelerate the closure of a coal plant and accelerate the building of additional renewable generation. This will cost Ameren's ratepayers an incremental \$4 billion. This compliance plan assumes that Ameren actually could have its new NGCC gas plant in commercial operation by 2020, which is highly unlikely, given the planning, permitting, construction and other infrastructure requirements involved, as described above. Thus, the interim goal limits the state's and Ameren's flexibility in determining how best to achieve EPA's ultimate goals, and in doing so, significantly increases costs to customers.

d. The interim compliance average period is inconsistent with state planning processes, market schedules and utility investment decision-making.

The proposed interim compliance average period is inconsistent with state planning processes, market schedules and utility investment decision-making. Although state plans are due in mid-2016, EPA has offered states the option of seeking an additional year (for an individual state

plan) or two (for multistate plans). *See 79 Fed. Reg.* at 34,916. Additional time to create workable state plans is a welcome flexibility. However, this extension conflicts with legislative schedules in many states. Several states already have noted that their legislatures do not meet every year and that the relevant future sessions are out of sync with the proposed timing for submission and approval of state plans. For example, both the Arkansas and Texas legislatures will not have sessions in 2016 and will meet again for the first time after the guidelines are finalized in 2017. To the extent that states need to pass new legislation to ensure that all elements of compliance plans are enforceable, the legislative calendar in some states will be an impediment to both ensuring that compliance plans are completed on time and allowing key compliance measures to reduce emission rates to move forward before 2020.

Similarly, for states that participate in competitive wholesale markets, the timing of state compliance plans does not account for already scheduled capacity auctions. For example, the PJM capacity auction addressing the 2017/2018 planning year took place in May 2014, the auction addressing the 2018/2019 planning year will occur before EPA finalizes the proposed guidelines in 2015 and the auction addressing the 2019/2020 planning year will occur in early 2016. Because units that are selected in these auctions are expected to be available to provide power in the relevant timeframes, decisions about which resources will be required to be available in 2020 will be made in early 2016, *before* the first set of state plans have been submitted to EPA. This will complicate state planning as it may limit reduction options available before 2020.

Furthermore, the 2020 compliance goals limit the ability of states, electric utilities and system operators to manage what could be a large number of simultaneously retiring coal-based units.

EPA's own analysis indicates that 46-49 GWs of coal-based units will close before 2020. *See* Resource Adequacy TSD at 8. This is in addition to the approximately 70 GWs of announced coal-based unit closures that will occur between 2010 and 2022. In total, almost a third of the U.S. existing coal-based fleet could be closed around the end of the decade. This will have significant implications for system reliability that must be managed, as discussed in section I, above. The ability to schedule these closures in a reasonable way is critical to maintaining reliability and minimizing costs—the interim compliance average deprives states of this tool. Finally, it takes years for electric utilities to plan, gain approval for and build infrastructure and other supporting projects.²⁵ This includes new efficient fossil-fuel plants; unit-level efficiency retrofits; new transmission lines to mitigate plant closures and to bring new energy sources to the grid; and a host of other compliance activities. Companies generally will not commit to make large financial investments—nor will state PUCs approve such investments—prior to final, EPA-approved state plans which could be well into 2018 or 2019. This uncertainty will challenge states' ability to meet and demonstrate compliance with the interim average emission rates starting in 2020. EPA's assumption that states can take significant steps to reduce emissions in advance of the start of the interim compliance period is thus inconsistent with its own regulatory timeline. The interim compliance goal does not take into account this lead time necessary to achieving reductions.

- e. The proposed interim compliance average period excludes emission reductions achieved before 2020 and perversely limits state incentives for initiating earlier emission reductions.**

²⁵ In many cases, site- and project-specific permit requirements and challenges can cause substantial construction delays for these projects. Utilities attempt to account for these potential hurdles in planning. However, any number of site-specific issues can cause lengthy delays in integrating new generation, transmission and distribution assets into the grid.

EPA calculated a 2012 emission rate for each state as part of the process to set the state-specific emission rate goals, but the interim average compliance period does not start until 2020. EPA proposes to limit the reductions that can be included in state plans to those achieved during the interim period. *See 79 Fed. Reg.* at 34,918. This means that states would not be able to include reductions that occur before 2020.²⁶ For example, states that undertake EE measures in 2015 will only be able to include the reductions from five years of those measures' estimated 10-year reduction life. Similarly, depending on whether a state chooses a rate- or mass-based approach, retiring coal-based units may have a limited impact on state emission rates, especially if EPA prohibits states from including reductions that were already on the books as of 2013 in state compliance plans.²⁷

In creating an interim compliance average measured over the period 2020-2029, EPA has created an arbitrary dividing line: planned emissions reductions that were “on the books” as of 2012 may not be counted, but the same reductions that were put “on the books” in 2013 or later would be counted. Section III.C., below, discusses the role of reductions achieved after 2012, but before 2020, in more detail.

f. The proposed interim compliance period does not allow sufficient time for RTOs and ISOs to evaluate and potentially alter market rules to accommodate changes in dispatch.

The changes in how demand is met envisioned by the proposed guidelines—increased dispatch of existing NGCC units, increased deployment of RE generation and use of existing RE

²⁶ As discussed *supra*, section II.A., the proposed guidelines do not recognize appropriately the value of state and electric utility efforts to reduce emissions prior to 2012.

²⁷ *See, infra*, section III.C., for a discussion of EPA's approach to including existing state programs and measures in approvable compliance plans. EPA should not limit states' ability to use reductions from existing state programs and measures in demonstrating compliance.

generation and the preservation of some existing nuclear units—will have significant implications for the wholesale electricity markets operated by RTOs and ISOs. Current market structures are built around the concept of security-constrained economic dispatch. But, state plans could require different approaches to dispatch. Because each market has its own set of rules, it is not immediately clear how the RTOs and ISOs will respond to such state plans. As a general matter (and at minimum), adequate time is required to ensure appropriate consideration and rule changes are made in each market. Replacing rate based interim targets with a state determined glide path with defined and verifiable milestones to achieve the final 2030 emission target levels help provide adequate time for a reliable transition to new market rules.

Wholesale electricity markets are under the jurisdiction of FERC, and any market changes will require FERC approval. Under the FPA, FERC is required to ensure that rates are “just and reasonable” and “not unduly discriminatory or preferential.” FPA sections 205(a) and 206(a). After state plans are submitted and approved, the RTOs and ISOs must evaluate and implement any market changes that will be needed to effectuate state compliance plans. The RTOs and ISOs will need time to determine any necessary market rule and system changes; vet these proposed changes through their stakeholder processes; obtain state and federal approvals, including FERC approval; and reliably implement the required changes. In RTO/ISO markets, the stakeholder process can take six to eight months, even on an expedited basis. FERC approval can take as long as a year or more, and implementation cannot start before final approval. Accordingly, even on the most expedited basis, RTOs and ISOs would have very little, if any time, to make market changes before 2020.

2. EPA’s proposed approach to state compliance plans can be used to promote state flexibility while ensuring that the 2030 goals are achieved.

States should be able to choose a reasonable emission reduction glide path that achieves the 2030 goal. Requiring that states demonstrate compliance with the 2030 goal through implementation of the EPA-approved plan, without reference to the proposed interim 2020-2029 average goal, would give states sufficient flexibility to design workable compliance plans which establish reasonable compliance glide paths consistent with ensuring reliability and protecting consumer interests. This would allow states to ensure that there is sufficient time to complete needed infrastructure development (including electric and/or gas transmission) in order to provide reliable power, and would reduce concerns regarding the system impacts of abrupt shifts in dispatch between existing coal- and gas-based units. It would eliminate conflicts between the timing of the interim period and legislative calendars, market rules and utility investment schedules. Finally, it also would recognize and value reductions achieved since 2012, encouraging early action where possible.

Eliminating the interim compliance average goal does not require a fundamental altering of the proposed guidelines. Instead, the proposed guidelines already are designed to allow states to develop their own compliance plans, and a description of the reduction trajectory to 2030 is a required element of state plans. EPA can and should use the proposed approach to state plans to ensure that state plans and emission reduction glide paths are designed to meet—and do actually achieve—the 2030 goals, with the ability to make corrective actions or allow for alternative compliance paths if new technologies or market conditions change requirements.

Importantly, even without the interim average compliance goal, EPA still will review and approve proposed state plans and emission reduction glide paths. Even under the proposed

guidelines, EPA would be able to disapprove proposed plans and glide paths that do not meet the minimum requirements and that do not demonstrate satisfactorily how the 2030 goals will be achieved. *See 79 Fed. Reg.* at 34,916. Allowing states to design emission reduction glide paths as part of their state plans would not undermine the overarching goals of the proposed guidelines. Further, as discussed below, other elements of EPA's proposed approach to state plans ensure that states make reasonable and verifiable progress toward the 2030 goal, report that progress to EPA and take corrective measures if needed. Ultimately, if states do not show progress toward the 2030 goal, EPA could call for a state to revise its compliance plan or implement its own federal plan. *See 79 Fed. Reg.* at 34,908.

The requirements for state plans are detailed and rigorous. *See id.* at 34,911-14. Particular elements of the state plans process require discussion as they demonstrate that EPA can allow states to design their own reasonable reduction glide paths and ensure that reductions are being achieved. First, the proposed guidelines require that states demonstrate continuous progress towards the 2030 goal and verify their performance through annual reporting of emission performance to EPA. Starting in 2022, states would be required to submit annual reports detailing plan implementation and progress, including a comparison of actual plan performance against projected plan performance. *See id.* at 34,914. In this way, EPA can monitor if states are making progress toward the 2030 goals and whether states are achieving reductions consistent with the proposed glide paths.

Second, the guidelines require that state plans must include periodic programmatic milestones to show progress toward implementation. These milestones are required to have specific dates for achievement. This requirement prevents states from delaying reductions. *See id.* at 34,912.

States plans also must identify additional measures that they will adopt and enforce in the event that an annual emissions progress report shows that the state's emission performance is not within 10 percent of the emissions performance path projected in the state plan. *See id.* These corrective measures would have to be implemented soon after a state report indicated that reductions were not being achieved consistent with the glide path, further ensuring that states could not delay reductions and that progress continues to be made toward the 2030 goals. *See id.*

Importantly, the proposed guidelines allow for states to propose modifications to approved plans to update or alter existing enforceable measures or add new enforceable measures. *See id.* at 34,917. This is an important state flexibility as it allows states to address changing circumstances over the long life of compliance. It is not likely that plans developed in 2016 would reflect the emission reduction options available in 2025, nor could they. Plans developed in 2016 also may not be able to appropriately address the requirements of the interconnected power system in the future. As discussed, implementation of the Building Blocks simultaneously will require fundamental changes in how the power system is operated and planned—many of these changes cannot be anticipated at the time state plans are submitted and before implementation has begun.²⁸ Allowing states to revisit plans to adjust glide paths or enforceable reductions actions and measures is both reasonable and necessary to ensure the

²⁸ As noted, *supra*, section II, EPA should consider state-specific factors when finalizing the 2030 goals to ensure that they are achievable.

continued reliable provision of electricity to customers and to reflect unanticipated circumstances.

However, the proposed regulations potentially limit states' flexibility to propose amendments to their compliance plans and are inconsistent with the preamble's clear statement that states can seek EPA approval for modified plans. Specifically, the proposed regulations could be read to limit states' ability to propose modifications only where a modification is necessary in order to ensure that the emission performance goals will be met. *See* proposed 40 C.F.R. § 60.5785, 79 *Fed. Reg.* at 34,954 ("If one (or more) of the elements of the state plan set in § 60.5740 *require revision with respect to reaching the emission performance goal set in § 60.5765* a request may be submitted to the Administrator indicating the proposed corrections to the state plan to ensure the emission performance goal is met.")(emphasis added). This seemingly would prevent a state from amending its plan in a circumstance where it was projected to meet its performance goals, but nonetheless determined that it could better provide reliable power to its citizens using a different mix of emission reduction measures.

States should not be limited to modifying plans only to address the failure of a plan element to perform as projected. As discussed, states need the flexibility to modify compliance plans and emission glide paths to address changing technology and the needs of the interconnected power sector. Each state should be allowed to modify its state compliance plan as long as it can demonstrate compliance with the 2030 emission goals. New generation or energy storage technologies that provide a cleaner, more reliable or cost effective path to achieve the 2030 goals should be allowed to replace existing elements of the state compliance plan. As EPA notes, as

long as states can continue to demonstrate that plans are designed to achieve the 2030 goals, states should be able to propose modifications. *See 79 Fed. Reg.* at 34,917 (“During the course of implementation of an approved state plan, a state may wish to update or alter one or more of the enforceable measures in the state plan, or replace certain existing measures with new measures. The EPA proposes that the state may revise its state plan provided that the revision does not result in reducing the required emission performance for affected EGUs specified in the original approved plan.”). EPA should clarify the proposed regulation accordingly.

3. The final guidelines should recognize a range of options for defining approvable emission reduction glide paths and state plans.

As discussed, EPA has clear authority to approve or disapprove state compliance plans and emission reduction glide paths. As set forth in the proposed guidelines, EPA will assess whether state plans are approvable using four general criteria. *See id.* at 34,909. First, the state plan must contain enforceable measures that reduce EGU CO₂ emissions; second, these measures must be projected to achieve emission performance equivalent to or better than the proposed 2030 goal; third, reductions must be quantifiable and verifiable; and fourth, the plan must include a process for reporting on implementation and emission performance and implementation of corrective measures, if necessary. *See id.* As a preliminary matter, EPA should make clear that it will not disapprove any plan that satisfies these four criteria.

There are a range of mechanisms for states to consider to determine potentially approvable, reasonable emission glide paths. As discussed in section III.E., below, EPA already has recognized that states can include non-BSER measures in compliance plans. *See id.* at 34,923-34. Similarly, approvable emission reduction glide paths do not have to be based exclusively on the actions and measures that EPA proposes constitute BSER. The following is a discussion of

some of the options states could consider. It is not intended to be exclusive or to limit state flexibility or choice in designing workable compliance plans.

a. Existing trading programs could be used to define state compliance glide paths.

An approvable plan or emission reduction glide path could take advantage of existing state programs. Further, any final guidelines should recognize, as noted in the proposed guidelines, that existing cap-and-trade programs under RGGI and California's A.B. 32 programs could be part of state plans and define an emission reduction trajectory for affected existing EGUs in those states. *See id.* at 34,838.

b. Federally enforceable coal plant retirements could also be used to define state compliance glide paths.

Under section 111(d) of the CAA, EPA is required, when promulgating a standard of performance under section 111(d), to take into consideration the remaining useful lives of the sources in the category of sources to which such standard applies. However, in proposing interim goals that effectively obligate the early retirement of coal resources in some states, EPA does not address the remaining useful lives of these resources, as well as other provisions of the CAA which may require the installation of major environmental controls or have resulted in established retirement dates.

Another option states should be able to pursue to define compliance glide paths would be the use of coal plant retirements, which is consistent with EPA's approach to compliance in other CAA

programs.²⁹ CAA programs with a similar federal-state policymaking process as is required under section 111(d) include the regional haze program and related BART emission standards.

In the regional haze context, EPA has allowed and approved state implementation plans that rely on a variety of different types of early coal plant retirement commitments to define a state's regional haze BART and reasonable progress compliance glide paths, so long as the retirements occur before a benchmark date and are legally enforceable.

- In considering Washington State's regional haze SIP, EPA accepted a Revised BART compliance option using a staggered decommissioning schedule that was required under unrelated State laws limiting GHG emissions.³⁰
- EPA approved an Oregon regional haze SIP that set a Revised BART emissions limit based on a voluntary, operator-set, enforceable retirement date.³¹
- Finally, EPA approved a Revised BART emission limit in a Wyoming regional haze SIP based on an early retirement date that corresponded with the end of the facility's depreciable life as determined by and made enforceable by the owner's economic regulator, the Wyoming Public Service Commission.³²

²⁹ EPA also has allowed regulated units to use retirement as a compliance tool in regulatory regimes outside of the CAA. For example, in the recently finalized cooling water intake structures rule, EPA allows facilities to use plant retirement as a means of compliance with both impingement and entrainment standards. See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, 79 Fed. Reg. 48,300, 48,332 (Aug. 15, 2014). Additionally, state clean water agencies are provided the flexibility to take into account a plant's remaining useful life in determining the appropriate entrainment standard. See *id.* at 48,376.

³⁰ See *Approval and Promulgation of Washington Regional Haze State Implementation Plan*, 77 Fed. Reg. 30,470 (May 23, 2012).

³¹ See *Approval and Promulgation of Oregon Regional Haze State Implementation Plan*, 76 Fed. Reg. 38,997, 38,999 (July 5, 2011).

³² See *Approval and Promulgation of Wyoming Regional Haze State Implementation Plan*, 79 Fed. Reg. 5,032, 5,165 (Jan. 30, 2014).

Consistent with these precedents, states should be allowed to use different types of retirement commitments to define, in part, their reduction glide paths and milestones to achieve the proposed section 111(d) 2030 goals—subject to EPA approval and annual compliance reporting.

In addition, several existing coal-fueled coal plants have recently undergone major retrofits to install pollution control equipment or will be required to install significant control equipment in the near future under EPA programs such as the regional haze program and related BART emission standards. In most cases, EPA justified the costs of installing these controls based on operating the coal units at high capacity factors over a twenty-year life. The proposed interim goals do not allow a state to ensure the useful life of these recent investments. If these coal units are retired earlier than expected, significant stranded assets could result.

c. RTO dispatch could be used to define state compliance glide paths.

States also could rely on other existing market mechanisms to define emission reduction glide paths. For example, the competitive wholesale markets administered by RTOs could be used to define a reduction trajectory for states. Under such an approach, states could choose to require in-state resources to include a carbon adder pre-determined by EPA when bidding resources into the market. This would alter the dispatch of units to better reflect their CO₂ emissions and provide a mechanism for continued emission reductions from existing units in a way that both respected system requirements and ensured reliable operation of the portions of the grid administered by the RTOs.

EPA could provide that while the carbon adder is used to affect dispatch, states would not be required to file annual compliance reports or otherwise demonstrate compliance with the

proposed guidelines in recognition of the fact that the maximum amount of re-dispatch that could be supported by the system operated by the RTO would be accomplished. This “safe harbor” would give states and electric utilities time to undertake actions and measures that result in emission reductions later, in recognition of, as discussed above, the infrastructure challenges related to implementing Building Blocks 1 and 2 and the timing issues related to implementing legislation necessary to implement Building Blocks 3 and 4. It would also provide an appropriate incentive to maintain zero carbon resources and avoid (at least in the short term) the concerns expressed above about the treatment of nuclear resources in the emission rate formula proposal.

Importantly, because the carbon adder relies on existing market structures, it could be implemented soon after state compliance plans are approved (and before 2020) to start reducing emissions. As noted, EPA should strive to create state flexibility that promotes early achievement of emission reductions. Further, to address concerns about costs for electricity customers, the carbon adder could be collected by the market operators and then used to offset increased costs to customers, ensuring that electricity remains affordable for end-users.

To support the potential use of this option to define state glide paths, the final guidelines should recognize the value of using existing market dispatch structures to achieve emission reductions and specifically note that states could pursue this option as part of an approvable plan. Further,

the final guidelines could include a carbon adder value for states to require affected units to use when bidding into competitive markets.³³

4. The NODA includes discussion of mechanisms that could address near-term compliance concerns for some states.

As discussed, the recently-released NODA recognizes that many stakeholders have concerns about the near-term compliance challenges created by the proposed guidelines. In particular, EPA notes that some commenters have suggested, consistent with the concerns raised in these comments, that

calculating the interim goals on the basis of achieving the shift in generation assumed under building block 2 by 2020...requires states to achieve such a significant portion of the required CO₂ emission reductions early in the interim period that it defeats the intended purpose of providing states flexibility in how they may achieve the required emission reductions. In addition, we have heard that there may be technical challenges associated with achieving all of the reductions that state would be required to make as early as 2020, when the interim period commences.

79 *Fed. Reg.* at 64,545.

Because of these concerns, EPA suggests it will consider additional stakeholder ideas, such as those regarding the 2020-2029 glide path, to ensure that the final guidelines provide states with flexibility to timely make reductions, develop cost-effective compliance plans and respond to unexpected demands on the power system. *See id.* As discussed above, eliminating the interim compliance goal and allowing states to choose a reasonable glide path to achieve their individual 2030 goals based on objective criteria outlined by EPA in the final guidelines would be the most appropriate way to help ensure that states can design cost-effective strategies to reduce emissions and would eliminate the significant technical challenges associated with requiring the majority of

³³ EEI member comments will provide more detail on this possible approach for states to define compliance glide paths using existing market structures.

the reductions to be achieved on or before 2020. It also would allow states, electric companies and system operators to plan for and implement changes to the interconnected power system in a way that would help support reliability in the case of unexpected demands on the power system, such as extreme weather events. Therefore, while the phase-in approaches discussed in the NODA are an improvement over the proposed guidelines, they are insufficient to address all of the concerns raised in these comments.

In the NODA, EPA discusses two ways of addressing concerns raised by stakeholders to address concerns about the glide path: (1) allowing states to credit early CO₂ emission reductions; and (2) phasing in the increased utilization of existing NGCC units under Building Block 2 over time, similar to the phase in of reductions under Building Blocks 3 and 4. *See 79 Fed. Reg.* at 64,545. Each of these options, which are discussed in turn, below, could address some of the concerns about the 2020-2029 glide path that have been raised by commenters. However, neither provides states the same ability to design cost-effective compliance plans that are consistent with the technical realities of shifting generation between existing coal- and gas-based units that would be provided by eliminating the interim goals.

d. States should have the option to recognize early reductions as a way to address concerns about the 2020-2029 glide path.

In the NODA, EPA notes that some stakeholders have suggested that “early reductions could be used as a way to ease the 2020-2029 glide path.” *Id.* EPA also notes that the proposed guidelines seek comment on whether credit for certain pre-2020 reductions could be used to reduce the overall amount of reductions that need to be achieved during the interim period. *See id.* at 64,545-46. The NODA also seeks comment on whether states could choose early implementation of state compliance plans, which would allow states to achieve the interim goals

by making some reductions earlier. *See id.* at 54,546. EPA asserts that either of these approaches would allow states to phase in reductions. *See id.*

Allowing states to recognize early action that reduces emissions between 2012 and the start of the interim compliance period is an important tool that could be useful to some states when designing compliance plans. As EPA notes, it is important to recognize early reductions so as not to create disincentives for pre-2020 reductions. *See id.* The final guidelines should permit early recognition of reductions as states develop their individual glide paths to the 2030 goal.

However, early recognition does not address fully the concerns raised in these comments about the interim compliance goal and the magnitude of reductions that are required before 2020. EPA notes that allowing states to credit some early reductions or state compliance periods earlier than 2020 could make it possible for “at least some states to take advantage...of RE and demand-side [EE] projects already under development and scheduled to be implemented prior to 2020 or by expediting other projects.” *Id.*³⁴ While states may be able to use some reductions from RE and EE measures, it is unlikely that these reductions would be significant enough to offset the need to increase significantly utilization of existing NGCC units to meet the interim goals. Credit for early RE and EE reductions also does not address infrastructure concerns or other technical challenges associated with increasing the utilization of existing NGCC units discussed extensively in sections II.C and III.A, above.

³⁴ As discussed *infra*, section III.D, the final guidelines should clarify that states can include reductions in compliance plans regardless of whether they are the result of measures or programs that were already “on the books” as of June 2014. The “on the books” limitation would reduce the amount of post-2012, pre-2020 reductions that states could use to address concerns about near-term compliance challenges.

In addition, given the timing challenges states face in submitting timely compliance plans for EPA approval, which are outlined above in section III.A.1., above, it is unlikely that states would be able to begin compliance plans early in order to take advantage of pre-2020 reductions. If states would like to do so, the final guidelines should make it clear that this is an option. Early recognition, however, is not sufficient to alleviate these concerns and does not obviate the need to eliminate the interim compliance goals.

e. Phasing in the increased utilization of existing NGCC units could help some states create a more gradual glide path, but would not address all concerns about state plan flexibility.

As discussed above, despite the fact that the interim goals can be met on an average basis for the 2020-2029 period, the structure of the numeric calculation for establishing the state goals assumes that all changes in dispatch between existing coal- and gas-based units has occurred by 2020. As discussed above, this front-loads reductions related to Building Block 2, creating significant technical challenges and limiting state flexibility in designing compliance plans. To address these concerns, EPA suggests that Building Block 2 reductions could be phased in. *See 79 Fed. Reg.* at 64,548. In the NODA, EPA seeks comment on two approaches for creating a phase-in schedule for Building Block 2. The first would examine whether, and to what extent, any additional natural gas pipeline infrastructure is needed to support increased use of existing natural-gas based generation. The second would consider the book life of existing generation assets, including any major upgrades to the assets, like pollution control retrofits. *See id.* at 64,548-49.

As a preliminary matter, phasing in reductions under Building Block 2, similar to the phase-in of reductions under Building Blocks 3 and 4, could address some of the near-term compliance challenges discussed in these comments for some states. In general, phasing in these reductions is more reasonable than assuming that all changes in dispatch between coal- and gas-based generation occurs before 2020. As EPA recognizes in establishing the Building Block 3 and 4 goals, it is appropriate to give states and electric utilities sufficient time to make system changes or create new programs. A phase-in of Building Block 2 reductions could allow for the necessary expansion of natural gas infrastructure to support increased utilization of existing NGCC units and could provide competitive markets time to review and adjust market rules, if needed.

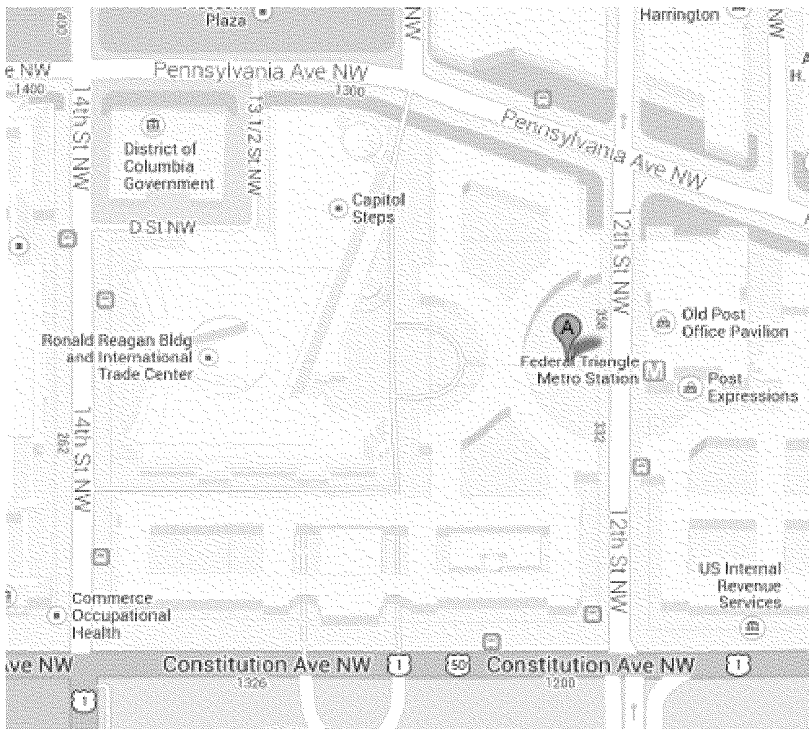
It is not clear from the NODA, however, exactly how EPA would structure a phase-in schedule for Building Block 2. Under the first option, EPA would account for the needed expansion in natural gas pipeline infrastructure, but the Agency has not provided any details as to how the Agency would determine which states need new capacity and how quickly it could be built. At minimum, EPA should recognize that it takes three to five years to plan, permit, contract for capacity, finance and build additional pipeline capacity. *See* Initial Reliability Review at 10. However, in general, it is difficult to see how the Agency could determine a phase-in rate for new pipeline capacity that would make sense for each state or accurately reflect state-specific infrastructure circumstances. Eliminating the interim goal so that states can determine the most appropriate phase-in schedule for Building Block 2 reductions would be simpler and better address state-specific concerns.

EPA's second approach would focus on the remaining book life of existing coal-based units, which EPA notes, would avoid stranding investments recently made in pollution control retrofits for coal-based units. *See* 79 Fed. Reg. at 64,549. While not clearly stated in the NODA, it appears that EPA would consider the remaining book life of certain coal-based units when calculating the re-dispatch potential available in a state. If EPA were to take this approach to phase in re-dispatch under Building Block 2, EPA should recognize both the remaining book life of units and any recent upgrades and major pollution control installations when setting state goals.³⁵

However, while this approach may be very important in some states as a way of providing a smoother glide path that does not strand investments, it would not address the 2020-2029 concerns of many other states with respect to the assumed changes in dispatch between coal- and gas-based units. In particular, it would not address any of the natural gas infrastructure concerns identified by electric utilities and states. If EPA determines to recognize remaining book life when calculating state goals under Building Block 2, it should be coupled with other approaches to address the full range of near-term compliance concerns.

³⁵ The NODA focuses solely on the book life of units, but it may be more appropriate to consider the depreciation schedule of the unit and any capital improvements. This would provide greater protection to consumers that ultimately bear the costs of these expenditures. Considering book life or depreciation schedules as a way to phase in Building Block 2 reductions does not satisfy EPA's obligation to consider the remaining useful life of units, as required by section 111(d). Book life is an accounting concept and does not measure the remaining useful life of an EGU.

From: Browne, Cynthia
Location: DCRoomARN5415PolyPCTB/DC-ARN-OAR | 1200 Pennsylvania Avenue, NW, William Jefferson Clinton Federal Building, Washington, DC 20460
Importance: Normal
Subject: Meeting Re: UARG Response to EPA 111(d) Questions | WJCN 5415 | Conference: 1-
Conf Code Participant Code **Conf Code**
Start Date/Time: Thur 12/12/2013 7:00:00 PM
End Date/Time: Thur 12/12/2013 8:00:00 PM
FW: UARG Response to EPA 111(d) Questions; request for dialogue

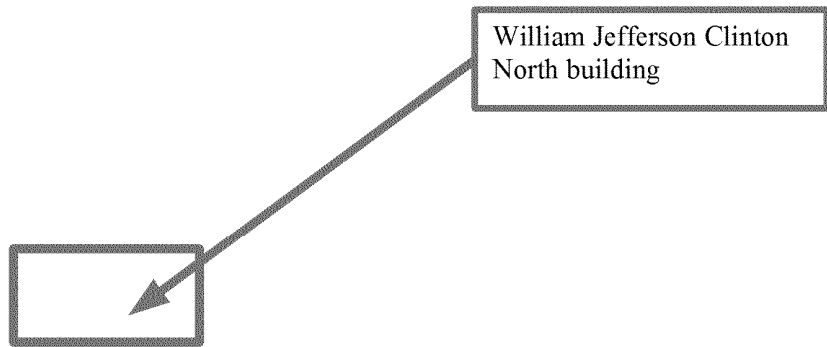


Directions and procedures: If you come by Metro the Federal Triangle metro stop is directly below the building entrances. You would leave the metro station and go up all three sets of escalators and turn right. You will see a set of stairs and glass Doors with EPA Signified on Glass. That is William Jefferson Clinton North (formerly Ariel Rios)

If you are coming by taxi, you would want to be dropped off on 12th NW, between Constitution Ave and Pennsylvania Ave. It is almost exactly half way between the two avenues on 12th. From 12th Street, facing the building with the EPA and American flags, walk toward the building and take the glass door on your right hand side with the escalators going down to the metro on your left. This again will be the North Lobby of the William Jefferson Clinton North.

Upon entering the lobby, the meeting attendees will be asked to pass through security and provide a photo ID for entrance. Let the guards know that you were instructed to call 202-564-7400. If you are travelling in a large group, you may want to arrive 10-15 minutes early in order to be on time for the meeting.

Map:





**Basis for Denial of Petitions to Reconsider the CAA Section
111(b) Standards of Performance for Greenhouse Gas
Emissions from New, Modified, and Reconstructed Fossil
Fuel-Fired Electric Utility Generating Units**

April 2016

This page intentionally left blank.

Basis for Denial of Petitions to Reconsider the CAA Section
111(b) Standards of Performance for Greenhouse Gas Emissions
from New, Modified, and Reconstructed Fossil Fuel-Fired
Electric Utility Generating Units

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Sectors Policies and Programs Division
Research Triangle Park, NC 27711

April 2016

This page intentionally left blank.

SUMMARY: The U.S. Environmental Protection Agency (EPA) received six petitions for reconsideration of the final Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, published in the Federal Register on October 23, 2015. The agency is denying five of these petitions, and deferring action on the petition of the Biogenic CO₂ Coalition.

Table of Contents

I. Executive Summary

II. Background

III. The Petitions

- A. Petition of Utility Air Regulatory Group (UARG)
- B. Petition of American Electric Power (AEP)
- C. Petition of Ameren Corp. (Ameren)
- D. Petition of the State of Wisconsin (WI)
- E. Petition of Energy and Environment Legal Institute (EELI)

IV. Response to the Petitions

- A. Response to UARG Petition
- B. Response to AEP Petition
- C. Response to Ameren Petition
- D. Response to State of Wisconsin Petition
- E. Response to EELI Petition

V. Conclusion

I. Executive Summary

Pursuant to section 111(b) of the Clean Air Act (“the Act”), the EPA has promulgated new source performance standards that establish, for the first-time, standards of performance for greenhouse gas emissions from newly constructed, modified, and reconstructed fossil fuel-fired electric utility generating units (EGUs). 80 FR 64510 (Oct. 23, 2015). The standard for newly constructed steam generating EGUs reflects the level of CO₂ emission reduction achievable by a highly efficient supercritical pulverized coal-fired boiler implementing partial carbon capture and sequestration (CCS) technology. 80 FR 64545. The standard for newly constructed and reconstructed stationary combustion turbines reflects the performance of a modern, well-performing natural gas-fired combined cycle (NGCC) unit. 80 FR 64612.¹

The EPA has received six petitions for reconsideration of the final standards of performance, focusing mostly on issues related to the standard of performance for newly constructed steam generating units and, more specifically, on the performance and cost of carbon capture technology. One petition maintains that the post-promulgation performance of carbon capture technology in actual operation at the Canadian SaskPower Boundary Dam Unit 3 facility shows that carbon capture is not yet adequately demonstrated at commercial scale. The EPA is denying reconsideration on this issue because, contrary to the petitioner’s contention, the facility’s performance, through March 2016, corroborates the EPA’s conclusion in the rulemaking that partial CCS is an adequately demonstrated technology within the meaning of CAA section 111(b). The same petition maintains that the SaskPower Boundary Dam facility uses a different carbon capture process than the one the EPA evaluated at proposal. This contention is incorrect. The petition further maintains that the EPA has not accounted for cost overruns at that facility. This contention is significantly exaggerated and not borne out by the facts.

The same petition maintains that the EPA failed to provide adequate public notice and opportunity to comment on the uncontrolled baseline emission rate (i.e., the emission rate of an uncontrolled coal-fired boiler) that it used as the starting point for calculating the percent of partial carbon capture needed to meet the applicable standard. In fact, the proposed rule provided ample public notice and opportunity to comment on this issue. The petition also maintains that the baseline is not achieved in practice, so that EPA’s cost estimates fail to account for some measure of increased boiler efficiency. The EPA disagrees with this contention, but even accepting the allegations, the costs of the standard would remain reasonable using the same methodology the EPA used in the rulemaking for assessing cost reasonableness. Another objection raised regarding partial CCS in this petition is that the EPA’s cost estimates of partial carbon capture reflect an inappropriate methodology for scaling down full carbon capture costs to partial capture costs. The EPA is denying reconsideration on this issue because the scaling methodology used in the rulemaking is well-established and normative, and the petition presents no legitimate reason to deviate from this standard methodology.

¹ The EPA also set standards for reconstructed steam EGUs and for those units that make large modifications. The EPA withdrew proposes standards for modified stationary combustion turbines. This is discussed in greater detail in the preamble for the final rule. No petitioners raised issues associated with the standards for modified or reconstructed steam EGUs.

Other petitioners address the partial CCS-based standard for newly constructed steam generating EGUs, but these petitions simply reiterate issues already raised in their rulemaking comments. The EPA has already addressed these comments in the preamble to the final rule and in the Response to Comment document. These petitions are untimely and the EPA is therefore denying them.

The remaining petition addressing the partial CCS-based standard alleges that the rulemaking process was tainted by impermissible communications involving an EPA official and various members of non-governmental organizations. This petition's legal theory is flawed, and the petition rests on a plethora of inaccurate factual assertions. The EPA is accordingly denying this petition.

The final rule also contains standards for stationary combustion turbines, and one of the petitions discussed above also challenges the definition of "base load rating" included as part of that standard. The EPA is denying reconsideration of this issue because the decision to include the heat input from duct burners in the definition of "base load rating" was not only reasonable, but advantageous to the regulated industry.

Two of the petitions – from the Biogenic CO₂ Coalition and from the State of Wisconsin – raise issues associated with the agency's treatment of biomass emissions when co-fired with fossil fuels. The EPA is deferring action on this issue pending further on-going consideration of the underlying issue of whether and how to account for biomass, for purposes of compliance with applicable standards, when co-firing with fossil fuels.

The EPA is accordingly denying five of the six petitions for reconsideration, and deferring action on the remaining petition.

II. Background

Section 307(d)(7)(B) of the CAA requires the EPA to convene a proceeding for reconsideration of a rule if a party raising an objection to the rule "can demonstrate to the Administrator that it was impracticable to raise such objection within [during the public comment period] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." The requirement to convene a proceeding to reconsider a rule is thus based on the petitioner demonstrating to the EPA both: (1) that it was impracticable to raise the objection during the comment period, or that the grounds for such objection arose after the comment period but within the time specified for judicial review (i.e., within 60 days after publication of the final rulemaking notice in the **Federal Register**, see CAA section 307(b)(1)); and (2) that the objection is of central relevance to the outcome of the rule.

In the EPA's view, an objection is of central relevance to the outcome of the final rule only if it provides substantial support for the argument that the promulgated regulation should be revised. See, e.g., the EPA's Denial of the Petitions to Reconsider the Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202 of the Clean Air Act, 75 FR 49556, 49561 (August 13, 2010); see also *Coalition for Responsible Regulation v. EPA*, 684 F.3d 102, 125 (D.C. Cir. 2012) (acknowledging and applying the EPA's interpretation of the central relevance criterion); *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008) (holding that

a petitioner fails to demonstrate that its objection is of central relevance when the petitioner “vaguely alludes to EPA’s incorrect factual assumptions,” but “fails to support [its] assertion” (internal quotation omitted).² Put another way, an objection is of central relevance to the outcome of the rule if the EPA would have reached a different outcome in the rulemaking if the objection has merit. Should the EPA deny petitions for reconsideration, “EPA certainly may ... provide an explanation for that denial, including by providing support for that decision, without triggering a new round of notice and comment for the rule.” *Coalition for Responsible Regulation*, 684 F. 3d at 126.

The EPA has received six petitions for reconsideration of the CAA section 111(b) greenhouse gas (GHG) new source performance standard (NSPS) from the following entities: the Utility Air Regulatory Group (UARG); American Electric Power (AEP); Ameren Corp. (Ameren); the Energy and Environmental Legal Institute (EELI); State of Wisconsin (WI); and the Biogenic CO₂ Coalition. The EPA is denying all but the last of these petitions as not satisfying one or both of the statutory conditions for compelled reconsideration. The EPA is deferring action on the issue raised in the petitions of the Biogenic CO₂ Coalition and the State of Wisconsin regarding treatment of biomass emissions pending our further on-going consideration of the underlying issue of whether and how to account for biomass emissions when co-firing with fossil fuels. We discuss in turn each of the five petitions we are denying.

III. The Petitions

A. *Petition of Utility Air Regulatory Group (UARG)*

UARG’s petition seeks reconsideration of several issues. First, UARG maintains that the operational experience with the newly installed carbon capture system³ at the SaskPower Boundary Dam Unit 3 (BD3) belies EPA’s reliance on this facility’s operating experience in support of the agency’s conclusion that carbon capture is an adequately demonstrated technology within the meaning of section 111 of the Act. Specifically, UARG maintains that BD3’s carbon capture system has experienced significant operating issues, including prolonged shutdowns, and has failed to reach its 90 percent capture design level. The petition further states that the company has incurred financial penalties for failing to provide contractually agreed upon amounts of CO₂ to its sequestration site (where the CO₂ is used for enhanced oil recovery (EOR)), again because of these operational shutdowns and other problems. The petition suggests that these operational issues have caused SaskPower to reconsider its announced plans to retrofit others of its units with carbon capture systems, quoting the company’s chief executive officer as stating, “[w]e need a year of stable operation near maximum performance to really test the

² See also CAA sections 307(d)(8) and (d)(9)(D)(iii), which likewise apply a “central relevance” criterion to judicial review of alleged procedural errors, requiring that the error be essentially outcome-determinative: “so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been substantially changed” if a procedural error had not occurred.

³ UARG refers to “CCS” – carbon capture and sequestration (or storage) – throughout this part of its petition, but the issues it raises relate entirely to operation of the carbon capture system, not the transportation or sequestration/storage parts of the project (beyond its assertion that Boundary Dam has failed to provide the volume of CO₂ for sequestration specified by contract and has incurred financial penalties as a result).

technology and commercial viability going forward” (UARG petition Exh. I). UARG also states that the carbon capture system in use at BD3 served as the basis for the Department of Energy’s National Energy Technology Laboratory (NETL) cost estimates for carbon capture systems, which were in turn used by the EPA for its cost estimations in the rulemaking, and that BD3 is now experiencing costs not accounted for in the NETL estimates.

Finally, UARG states that BD3 has not shown that it could achieve the promulgated standard of 1,400 lb CO₂/MWh-g (demonstrated on a 12-month basis). The petition contains various supporting exhibits, most of which are press accounts of Saskatchewan (Canada) Parliamentary debates discussing BD3’s operations. The petition claims that this information is of central relevance since the performance of BD3 provides the primary rationale for the EPA’s finding that carbon capture is adequately demonstrated. (UARG Petition p. 8) Because BD3’s operating history reflects post-proposal, and in many instances, post-promulgation developments, commenters could not have been presented the information to the EPA during the rulemaking.

The second issue raised in the UARG petition (effectively joined by petitioners AEP and State of Wisconsin, which raise the identical issue in their petitions) is that the EPA selected an arbitrary uncontrolled baseline CO₂ emission rate from which to calculate quantified CO₂ emission reductions, and did so without providing adequate opportunity for public comment. Specifically, UARG maintains that at proposal the EPA indicated that the Best System of Emission Reduction (BSER) for CO₂ was partial CO₂ capture applied to an emission stream reflecting performance of a supercritical pulverized coal boiler (SCPC). The baseline should thus be the initial performance of a SCPC unit. UARG states that “[t]he proposed GHG NSPS did not in any way address the baseline emission rate for new SCPC units or analyze the proposed standard’s achievability for such units. Instead, the proposal only conceptually described ‘the emission reductions that can be achieved by an IGCC [Integrated Gas Combined Cycle] with a single-stage ... reactor and a two-stage acid gas removal system’ – i.e., an IGCC applying pre-combustion CCS,” citing to 79 FR 1470 (UARG Petition p. 9). In the final rule, according to UARG, the BSER is partial CO₂ capture applied to an emission stream reflecting performance of an ultra-supercritical pulverized coal (USCPC) boiler, performing at hitherto undisclosed levels of between 1,618 to 1,737 lb CO₂/MWh (depending on the type of coal being utilized). UARG maintains that SCPC units cannot meet this baseline level, and therefore that the final standard would not be achievable without additional carbon capture, which UARG maintains the EPA has implicitly found would not be cost-effective. UARG further maintains that even ultra-supercritical boilers cannot meet the baseline levels over the 12-month operating period specified in the rule for compliance. (UARG Pet. p. 13.) According to the Petition, the issue is of central relevance to the rule’s outcome because it pertains to the standard itself.

UARG’s third issue relates to the EPA’s estimates of CCS capital costs, which UARG maintains are arbitrarily low. UARG asserts that the EPA “did not address the capital cost of partial CCS” at proposal (UARG Pet. p. 14), and that its estimates of capital costs for the final rule are erroneous because the costs a) do not reflect costs of actual projects utilizing CCS; b) fail to reflect the proper baseline, a well-operated SCPC (reiterating issue 2 above); c) fail to include a design margin; and d) are based on NETL reports that misapply NETL’s own methodology for estimating costs when scaling. The issue is of central relevance, according to the Petition, because the purported costing errors call into question the EPA’s conclusion that CCS is an adequately demonstrated technology, considering its cost.

The Petition also seeks reconsideration of two issues that are ancillary to the promulgated standards of performance. UARG maintains that the EPA changed the applicability criteria for stationary combustion turbines without proper notice, and that this issue is of central relevance to the rule's outcome since it relates to which units are subject to the standard of performance. Specifically, UARG argues that the EPA should reconsider its decision to include the heat input from duct burners in the definition of "base load rating," 40 CFR 60.5580, because UARG did not have an opportunity to comment on this aspect of the final rule. UARG explains that this change affects the applicability criteria for stationary combustion turbines, which only subject turbines that have "a base load rating greater than 260 GJ/h (250 MMBtu/h) of fossil fuel (either alone or in combination with any other fuel)" to the requirements of the rule. 40 CFR 60.5509(a)(1). UARG objects to the inclusion of the heat input from duct burners in the definition of "base load rating" because the approach is allegedly inconsistent with the approach taken in the proposed rule and the EPA's historical treatment of stationary combustion turbines under Subpart KKKK. UARG asserts that the issue is centrally relevant to the Rule because it implicates the fundamental question of what units are subject to the 111(b) GHG NSPS.

The last issue raised in UARG's petition is that the final rule unreasonably restricts the entities who may submit electronic reports under the final standard. The petition maintains that the final rule purportedly reflected public comments submitted by UARG, but misinterpreted those comments. UARG maintains that this issue is of central relevance to the outcome of the rule as it relates to who can make submissions under the rule.

B. Petition of American Electric Power (AEP)

American Electric Power Co. (AEP) maintains that the EPA misinterpreted and misapplied information relating to a project whereby AEP retrofitted one of its operating plants (the Mountaineer Power Plant, New Haven, WV) with CCS. AEP maintains that it (and others) submitted extensive comments regarding the Mountaineer Power Plant retrofit, and that, despite these comments, the final rule unaccountably still indicates that the Mountaineer project provides support for partial CCS being an appropriate best system of emission reduction. The petition does not maintain that AEP lacked adequate notice of issues pertaining to the Mountaineer project, or that the issue of the plant's performance is of central relevance to the outcome of the rulemaking.

AEP also maintains that certain alternative compliance options for meeting the standard, namely using natural gas co-firing in either a steam generating unit (boiler) or Integrated Gasification Combined Cycle (IGCC) unit, are not technically demonstrated, and seeks reconsideration of this finding. The State of Wisconsin likewise seeks reconsideration of this finding, for similar reasons. Finally, as noted above, AEP also contends that the EPA selected an arbitrary uncontrolled baseline CO₂ emission rate from which to calculate quantified CO₂ emission reductions, and did so without providing adequate opportunity for public comment.

C. Petition of Ameren Corp.

Ameren Corp. (Ameren) maintains that the CAA section 111(b) GHG NSPS, the CAA section 111(d) existing source standards of performance and emission guidelines, and the proposed federal plan requirements are closely intertwined and should be considered as a single unit of rules. The petition then mentions a series of issues relating exclusively to the CAA

section 111(d) existing source standards and emission guidelines as (purportedly) necessitating reconsideration.⁴ The petition does not seek reconsideration of any specific issue in the section 111(b) rulemaking. The only mention of an issue specific to the section 111(b) NSPS is an allegation that partial CCS is not yet adequately demonstrated (Ameren Petition p. 24) (with a supporting quotation that relates to full CCS rather than partial CCS). The petition does not allege that Ameren lacked notice and opportunity to comment on this issue.

D. Petition of State of Wisconsin

The State of Wisconsin seeks reconsideration of various issues raised in its public comments, which it asserts that the EPA failed to address. These issues include whether CCS is adequately demonstrated when it is an “emerging technology”; whether the standard is arbitrary because it is more stringent than a best available control technology (BACT) limit for a coal-fired plant in Wisconsin; and whether the standard impermissibly disadvantages Wisconsin sources for various reasons, including lack of geologic sequestration capacity within the state. The petition further maintains that the EPA did not account for the full cost of transporting captured CO₂, at least for Wisconsin sources. Additionally, with respect to combustion turbines, the petition argues that EPA set a standard of performance for base load units that cannot be achieved by simple cycle technology. Finally, the petition raises a number of issues in common with the other petitions, as noted above.

Similar to the AEP petition, the Wisconsin petition maintains that co-firing of natural gas in either a steam generating unit (boiler) or Integrated Gasification Combined Cycle (IGCC) unit, has not been technically demonstrated, and the petition seeks reconsideration of the EPA’s finding that natural gas co-firing can serve as an alternative compliance option for meeting the standards. Finally, as noted above, the petition also contends that the EPA selected an arbitrary uncontrolled baseline CO₂ emission rate from which to calculate quantified CO₂ emission reductions, and did so without providing adequate opportunity for public comment. The petition does not address the section 307(d) criteria for granting reconsideration.

E. Petition of Energy and Environment Legal Institute (EELI)

EELI maintains that the final standard of performance is tainted due to pre-proposal communications between a particular EPA official and representatives of environmental non-governmental organizations (NGOs), which the petition characterizes as illegal *ex parte* contacts that are of central relevance to this proceeding because of the purported influence the communications had on the standard.

IV. Response to Petitions

A. Response to UARG Petition

1. Performance of SaskPower Boundary Dam Unit 3 (“BD3”)

⁴ Note that Ameren Corp. also submitted essentially the same petition to the agency requesting reconsideration of these issues in the CAA section 111(d) emission guidelines.

SaskPower's Boundary Dam has installed retrofit "full CCS"⁵ technology on its Unit 3 boiler and is currently operating it at commercial scale. UARG, in essence, maintains that the post-proposal/post-promulgation performance of BD3 shows that the CCS system is not working, and, therefore shows that the technology is not adequately demonstrated at the facility. The petition further states that since the performance of the BD3 system was the critical element in the EPA's finding that partial CCS is an adequately demonstrated technology, the unit's subsequent operational failures undermine the entirety of the EPA's finding, and is necessarily an issue of central relevance to the outcome of the rulemaking. UARG further maintains that it lacked opportunity to comment on these issues because the critical elements of the BD3 performance occurred either after proposal or after the August 2015 promulgation date of the final standards.

The EPA agrees that the grounds for UARG's objection arose after the public comment period, but disagrees that the objection is of central relevance to the rule's outcome because the EPA did not rely solely on the expected performance of BD3 (see 80 FR 64550-556) and because the actual performance of BD3 confirms that partial CCS is adequately demonstrated at the facility, and thus corroborates the EPA's finding that the technology is adequately demonstrated.

The suggestion that BD3 has experienced operational failures calling into question the reliability, feasibility, or demonstrability of the carbon capture technology is greatly exaggerated and essentially incorrect. As described below, the CO₂ capture system at BD3 is operating successfully, the unit meets the Canadian performance standard for CO₂ emissions (which is more stringent than the U.S. standard), and it is producing more CO₂ for enhanced oil recovery than called for by contract. Operational issues in the first year of operation were related largely to ancillary systems and not to the carbon capture system, and appear to have been successfully resolved.

The BD3 carbon capture system commenced operation in October 2014. The system was shut down for two weeks in June 2015 for maintenance, and for nearly two months (most of September and all of October) in the fall of the same year for further maintenance.⁶ The system has operated with high reliability since.⁷ BD3 continued to generate electricity during the entire 18-month period, with the exception of the September maintenance period.⁸

⁵ As explained in both the proposal (79 FR 1469) and the final standards (80 FR 64548), "full CCS" means that the system is designed to capture 90 percent (or greater) of the CO₂ emissions from the plant usually by treating the entire combustion flue gas or syngas stream. "Full CCS" is distinguished from "partial CCS" in that the latter is a system that is designed to capture some amount less than 90 percent of the CO₂ emissions, often by treating only a portion (or slip stream) of the combustion flue gas or syngas stream.

⁶ SaskPower Report March 2016 posted at <http://www.saskpower.com/about-us/blog/bd3-status-update-march-2016/>.

⁷ Id., indicating that the system "was operational 82 of 91 days of the year, primarily due to planned maintenance, for a 90% reliability factor in the first quarter of 2016."

⁸ Id.

It is not unusual for plants to experience operational issues after first installing and operating a complex technical system. See, e.g., 79 FR 1482.⁹ However, according to SaskPower, most of the technical issues experienced by the unit in its initial year of operation involved ancillary equipment and control systems rather than technical issues that are directly attributable to the carbon capture system itself.¹⁰ For example, there were idiosyncratic issues associated with the design or misplacement of ordinary components – such as exhaust valves being installed too near intake valves. There was also a delay associated with the need to install a new, larger storage tank for the amine solvent and then to fix the tank, which the company described as being delivered with visible hairline cracks in the tank floor.¹¹ In addition, in the initial months of operation, the unit experienced some operational difficulties associated with SaskPower's ability to control the amine regeneration temperature because of a leaky steam valve. This resulted in overheating and subsequent degradation of the amine solvent.¹² While the leaky steam valve resulted in an overall degradation of the performance of the carbon capture system, few would characterize steam valve technology as “not adequately demonstrated” or “first-of-a-kind”. Nor is a cracked storage tank the type of development that raises issues regarding the feasibility of carbon capture technology.

The company brought the carbon capture system down in September and October of 2015 to address various operational issues related to sodium-based sub-micron particles that were fouling demisters at the exit of the SO₂ scrubber upstream of the carbon capture system.¹³ The issue was resolved and the carbon capture system resumed operation in November 2015.

The system has demonstrated high rates of CO₂ capture since its initial coming on-line. In its initial months of operation, the system operated at a relatively constant CO₂ removal rate of approximately 61.5 percent of its design capacity (or approximately 1,700 tons of CO₂ per day). Since November 2015, after the two month hiatus, the unit captured approximately 60,000 tons of CO₂ in November 2015 and approximately 61,000 tons of CO₂ in December 2015, capture

⁹ See also letter from SaskPower President and CEO Mike Marsh to Administrator Gina McCarthy (Nov. 17, 2015) (“[w]e have achieved an 80 per cent capture rate in our early operations; however, the capture rate has fluctuated over the course of the year. Since the launch, SaskPower has experience various problems with a number of sub-systems within the process and has worked to develop solution and to fix them. These challenges are not uncommon in a large-scale industrial project during the early stages of operation....”).

¹⁰ Memorandum of conversation between Dr. Nick Hutson (EPA) and Mr. Mike Monea (SaskPower), February 2, 2016; Email from Mr. Mike Monea (SaskPower) to Dr. Nick Hutson (EPA), February 2, 2016).

¹¹ Memorandum of conversation between Dr. Nick Hutson (EPA) and Mr. Mike Monea (SaskPower), February 2, 2016. See also SaskPower Press Release of Sept. 14, 2015 (<http://www.saskpower.com/about-us/media-information/newsreleases/large-piece-of-saskpower-equipment-makes-its-way-from-saskatoon-to-estevan/>), and UARG Petition Exh. G p. 2 which note the replacement of the amine storage tank, and note the storage tank's very substantial size. Exh. G (at p. 2) also notes the issue of the leaky valve.

¹² Memorandum of conversation between Dr. Nick Hutson (EPA) and Mr. Mike Monea (SaskPower), February 2, 2016.

¹³ <http://www.saskpower.com/about-us/blog/bd3-status-update-january-2016/>; Memorandum of conversation between Dr. Nick Hutson (EPA) and Mr. Mike Monea (SaskPower), February 2, 2016. The system was also down for maintenance for two weeks in June 2015.

rates exceeding 70 percent of design capacity.¹⁴ In January 2016, the unit captured approximately 85,000 tons¹⁵ – slightly better than 100 percent of design capacity, and an amount that exceeds the monthly quantity of CO₂ that SaskPower has contracted to provide to Cenovus Co. for EOR operations.¹⁶ Capture rates for February and March, 2016, are approximately 60 and 100 percent of design capacity respectively.¹⁷ SaskPower has, at several times, conducted so-called nameplate testing, designed to test the capture limits of the facility, and was able to achieve the intended 90 percent capture rates on those occasions.¹⁸ The company has stated publicly that it expects the carbon capture system to be operational 85 percent of the time in 2016 (allowing time off for routine scheduled maintenance) and to capture 800,000 tons of CO₂ over that year, a projected average capture rate of approximately 80 percent of design capacity.¹⁹

Over the one-year operating period from October 2014 through September 2015, even considering the facility downtime, BD3 captured approximately 415,000 tons of CO₂. This is a capture rate exceeding 40 percent,²⁰ which is significantly more efficient than the 12-month annual capture rate (reflecting partial carbon capture at an annual rate of approximately 16 to 23 percent depending on coal type) on which the section 111(b) new source standard is predicated.²¹ See 80 FR 64573-74. Indeed, the plant's capture amount would have comfortably satisfied the standard for a plant with five times the volume of CO₂ emissions (i.e., a 500 MW SCPC plant).²² From February 2015 through January 2016, the plant captured 625,000 tons of CO₂, a capture

¹⁴ Letter of January 20, 2016, from SaskPower CEO Mike Marsh to EPA Administrator Gina McCarthy, p. 1.

¹⁵ “In some months routine maintenance and inspection is planned and in other months, such as January, the facility can be operated nearly 100 per cent of the time. Over a year, we expect the facility to be up and running approximately 85 percent of the time... It allowed us to capture and sequester a record 84,976 tonnes of carbon dioxide. We continue to target the capture of 800,000 tonnes this year.” SaskPower Report January 2016 posted at <http://www.saskpower.com/about-us/blog/bd3-status-update-january-2016/>.

¹⁶ Email from Mr. Mike Monea (SaskPower) to Dr. Nick Hutson (EPA), Feb. 2, 2016; UARG Petition Exh. B.

¹⁷ SaskPower Report March 2016 posted at <http://www.saskpower.com/about-us/blog/bd3-status-update-march-2016/>.

¹⁸ Letter from Saskpower CEO Mike Marsh to Administrator Gina McCarthy, Nov. 17, 2015 p. 1; Letter from Saskpower CEO Mike Marsh to Administrator Gina McCarthy, Jan. 20, 2016 p. 1; email of February 2, 2016; see also the chart in UARG Petition Exh. H and Exh. J p. 2-3 showing individual days where the plant achieved a 90 percent capture rate. Boundary Dam conducted its most recent nameplate testing in December, 2015.

¹⁹ SaskPower Report January 2016 posted at <http://www.saskpower.com/about-us/blog/bd3-status-update-january-2016/>.

²⁰ The system is designed to capture 1 million tons of CO₂ per year. UARG Petition Exh. D; see also id. Exh. B, D, E p. 2, and G (all noting 400,000 tons of CO₂ captured in the initial year of operation), and Exh. C and D (noting 40% + capture rate in initial year of operation).

²¹ Letter of January 20, 2016, from CEO Mike Marsh to Administrator McCarthy p. 1; see also Exh. B, D, E (p. 2), H (p. 1 of 4), and J (p. 2-3) of UARG's petition, all of which likewise show that Boundary Dam has recovered more CO₂ over its initial 12 months of operation than would be required under the CAA section 111(b) NSPS.

²² See Table 12 of preamble to final rule (80 FR 64574) showing capture of 354,000 tons of CO₂ annually would be required for a 500 MW SCPC plant to meet the promulgated standard.

rate exceeding 60 percent, which is, as noted, well in excess of what the NSPS requires (notwithstanding downtime for the system in June, September, and October).²³ The initial capture rates for the months immediately following the two month maintenance period also greatly exceed those on which the NSPS are predicated, as does the plant's projected 2016 capture rate.²⁴

Equally important is that the plant's initial operational issues appear to be resolved, and that most of these operational issues were related, in any case, to ancillary systems at the plant, not to the carbon capture system. The unit's operation also bears out the EPA's prediction that the 12-month averaging period is "forgiving" and accommodates significant operational variability. 80 FR 64573 (12-month averaging period is "very forgiving of short-term excursions that can be associated with non-routine events such as start-ups"); Achievability TSD (July 31, 2015) at pp. 1-2 (similar finding).

Importantly, the carbon capture system at BD3 is a retrofit to an existing unit, which poses special complexities and difficulties that a new source would not experience.²⁵ One can reasonably assume that future plants will benefit from BD3's operational and startup experience, and need not encounter the same issues. See 80 FR 64565-66. BD3's carbon capture operations remain transparent to the general public with SaskPower providing regular updates on plant performance that are posted on their website www.saskpower.com (listed as "BD3 Update" on the site). In addition, SaskPower and BHP Billiton have established the "Carbon Capture and Storage Knowledge Centre" to help advance CCS as a means of managing greenhouse gas emissions.²⁶ SaskPower is also helping advance CCS knowledge and technology through the creation of the Shand Carbon Capture Test Facility (CCTF).²⁷ The CCTF provides technology developers with an opportunity to test new and emerging carbon capture systems for controlling carbon emissions from coal-fired power plants.

Although BD3's early operational issues reduced the volume of CO₂ it was able to deliver for EOR, because it has resolved those issues, it now "satisfies the volume needs of our carbon dioxide buyer," and, since November 2015, is generating more CO₂ than specified by

²³ <http://www.saskpower.com/about-us/blog/bd3-status-update-january-2016>.

²⁴ The unit has also achieved the more stringent Canadian emission limitation of 420 kg CO₂/MWh (926 lb CO₂/MWh) per calendar year. Email from Mr. Mike Monea (SaskPower) to Dr. Nick Hutson (EPA), Feb. 2, 2016.

²⁵ See 80 FR 64551 ("In fact, retrofit of [CCS] technology at an existing unit can be more challenging than incorporating the technology into the design of a new facility"); *id.* at 64557 ("Much has been written about the complexities of adding CCS systems to fossil fuel-fired power plants. Some commenters argued that the EPA minimized – or even ignored – these publicly-voiced concerns in the discussion presented in the ... proposal. On the contrary, the EPA has not minimized or ignored these complexities, but it is important to realize that most of these statements come in a different context: [n]amely, implementing full CCS, or retrofitting CCS onto existing power plants"); see also Comment Response 6.3-47 (special difficulties experienced by American Electric Power Mountaineer project due to it being a retrofit to an existing facility) and response B *infra* (response to petition of American Electric Power).

²⁶ <http://www.bhpbilliton.com/investors/news/bhp-billiton-and-saskpower-establish-carbon-capture-and-storage-knowledge-centre>.

²⁷ <http://saskpowerccs.com/ccs-projects/shand-carbon-capture-test-facility/>.

contract.²⁸ The company indicates that revenues from EOR will exceed any contract penalties for the 2015 operating year.²⁹ Moreover, some of the foregone revenue resulted from BD3 generating more CO₂ in its initial months of operation than the EOR buyer could accommodate.³⁰

The petition likewise quotes SaskPower CEO Mike Marsh as stating “we need a year of stable operation near maximum performance to really test the technology and commercial viability going forward”. (UARG Petition Exh. I, p. 1.) The statement is in the context of whether to retrofit full-scale CCS on the company’s fleet of coal boilers, and thus of minimal relevance in deciding here whether to reconsider a standard reflecting performance of partial capture of CO₂ by a newly constructed source. In addition, there is no requirement under the Act or in case law that a technology operate for any given period before it can be considered to be adequately demonstrated, and, in fact, under certain circumstances, the EPA may determine that a technology is adequately demonstrated even before it begins to operate. Moreover, SaskPower evidently views the carbon capture technology as operating successfully, as shown by its public letters and statements, which are part of the record here. Furthermore, as noted in the final rule, the BD3 project is only one of the examples of post-combustion capture that the agency relied on in its determination that post-combustion partial CCS has been adequately demonstrated. See 80 FR 64548.

In any case, the quote from CEO Marsh relates to SaskPower’s decision about whether or not to retrofit additional coal-fired units with CCS technology. As the EPA noted in both the proposed and final CAA 111(b) standards, coal-fired units currently face tremendous competitive pressure from other generation options – especially from natural gas-fired combustion turbines and renewable energy sources. See, e.g., 80 FR 64558-59 and 64641-42; see generally RIA chapter 4. SaskPower is faced with a requirement to either retire its aging fleet of coal-fired boilers or retrofit them with CCS technology (in order to meet the Canadian emission standard). Given these options, it certainly makes sense that the company would allow the BD3 system to operate for some time so that the company can “really test” not just the performance of the technology, but also the commercial viability of retrofitting its fleet of coal-fired boilers with the CCS system vis-à-vis other investment options for generating electricity.

The petition also suggests that BD3’s failure to operate at a day-to-day 90 percent capture rate shows the technology is not operating reliably because the plant system is designed to achieve a 90 percent capture rate. See, e.g., UARG Pet. Exh J pp. 2-2 to 2-3. The EPA disagrees. The plant has, in fact, achieved 90 percent capture when doing nameplate testing (i.e., pushing the technology to its design limit) and has operated at capture rates exceeding even its 90 percent design level, but the more important point is that the plant has operated and is operating reliably, and is now providing more CO₂ monthly than required by contract. It is meeting the Canadian

²⁸ Letter from Saskpower CEO Mike Marsh to Administrator Gina McCarthy, Jan. 20, 2016 p. 1.

²⁹ Memorandum of conversation between Dr. Nick Hutson (EPA) and Mr. Mike Monea (SaskPower), February 2, 2016; UARG Petition Exh. D p. 3.

³⁰ Email from Mr. Mike Monea (SaskPower) to Dr. Nick Hutson (EPA), Feb. 20, 2015 (EPA-HQ-OAR-2013-0495-11699) (“We are running about 75% capture, roughly 2,600 tonnes/d of 99.999% CO₂. Cenovus Energy is phasing in our CO₂ so we will have five months of lower sales for EOR to Cenovus.”); see also UARG Pet. Exh. D p. 2 (“In some of the months, it was running more efficient than Cenovus would take”).

CO₂ emission standards (which are more stringent than the NSPS at issue here). Even more basically, operational ‘hiccups’ in an initial year of operation are to be expected (see e.g., 79 FR 1482 (Jan. 14, 2014)), and do not, by themselves, show that a control technology is infeasible, or otherwise not demonstrated. The EPA believes that is the case here where plant managers and executives indicate that the operational problems involved are resolved (and, for the most part, were not attributable to the carbon capture system itself), and the plant is operating on a highly successful upward trajectory.

The EPA thus is denying this aspect of the petition as not showing that the objection is of central relevance to the outcome of the rulemaking. As just noted, the EPA did not project that plants would operate CCS without experiencing some initial operational issues,³¹ and established a standard with an extended averaging time to provide an ample compliance margin. See 79 FR 1481; 80 FR 64573. BD3 is operating successfully, and has demonstrated that it can achieve capture rates well in excess of its contractual obligations, as well as sufficient to achieve compliance with the (more stringent) Canadian CO₂ emission standard. More importantly, the retrofit carbon capture system at BD3 has demonstrated the ability to achieve carbon capture rates, over an extended averaging time, that are far in excess of the capture rates needed to comply with the standard established by the EPA for new steam generating EGUs under the subject rulemaking. The EPA thus believes that Boundary Dam’s performance corroborates rather than undermines a finding that partial CCS is an adequately demonstrated technology, within the meaning of section 111(b) of the Act.

2. Use of NETL (2015) Cost Estimates/Cost of Shell Cansolv Carbon Capture Technology

UARG also maintains that BD3 uses the Shell Cansolv carbon capture process, that the Cansolv process served as the basis for cost estimates from a National Energy Technology Laboratory (NETL) study that was issued in June 2015 (after the comment period), and that those cost estimates do not (and could not) reflect cost overruns experienced by BD3. More generally, UARG states that the EPA based its cost estimates for carbon capture at proposal on a different carbon capture technology, and maintains broadly that the public lacked opportunity to comment on the 2015 NETL cost estimates. UARG Petition pp. 7-8. None of these contentions justify reconsideration, and the EPA is accordingly denying this part of the petition.

It is well settled that agencies may rely on studies not subjected to notice and comment where those studies serve as additional support for the data and conclusions in a proposal, particularly where there is no change to the methodology by which the information is developed and assessed. See, e.g., *Chamber of Commerce v. SEC*, 443 F. 3d 890, 900 (D.C. Cir. 2006) (“further notice and comment are not required when additional fact gathering merely supplements information in the rulemaking record by checking or confirming prior assessments without changing methodology” (citing *Solite v. EPA*, 952 F.2d 473, 485 (D.C. Cir. 1991))). There was no methodological change here. The 2015 NETL report was an update (listed as “Revision 3”) of the studies that the EPA used at proposal. As is further explained below, all of these updates use the same basic methodology (e.g., a component-by-component cost evaluation of a post-combustion CCS system with the same key financial assumptions). The EPA used the

³¹ See, e.g., 79 FR 1482 (noting that a potential 84-month averaging time “offers increased operational flexibility and will tend to compensate for short-term emission excursions, which may especially occur at initial startup of the facility and the CCS system”).

NETL studies to derive the cost estimates presented in the proposal and then used the updated NETL studies to derive cost estimates for the final standards. The EPA then, as at proposal, compared those estimates to the cost of non-fossil fuel-fired electricity generating technologies, in particular technologies providing baseload dispatchable power, using the Levelized Cost of Electricity (LCOE) metric. Compare 79 FR 1475-78 and 80 FR 64560-563. As at proposal, carbon capture is considered to be a technology with cost estimates reflecting a next commercial offering (or next-of-a-kind) of the technology.³² As at proposal, the updated study remains a Class 4 feasibility study, with cost estimates presented with the same range (-15 to +30 percent uncertainty on the capital cost).³³ Consistent with earlier studies, the updated NETL study assumes high-risk financing for the carbon capture system.³⁴ There is the same level of transparency in each study, based on identical overall methodology for assessing and presenting costs for each operating system.

The 2015 NETL cost information supplements and corroborates information used at proposal. First, UARG is not correct in stating that the EPA considered a different carbon capture technology in its cost estimates for the final rule as compared to the one it used at proposal. For both the proposed and final standards, the EPA's cost estimates were for a new, highly efficient, coal-fired boiler implementing partial post-combustion CCS through the use of an amine-based capture system which scrubs CO₂ from a slip stream of the post-combustion flue gas. The CCS capture system (i.e., the equipment) was the same in both studies – only the solvents differ.³⁵ In the proposed action, the NETL studies that served as the basis for those costs assumed that the post-combustion CCS system used the Fluor Econamine solvent.³⁶ For the final action, the EPA relied on updated NETL studies that assumed the use of the Shell Cansolv solvent.³⁷ The Shell Cansolv amine solvent was used in the updated studies because it is the better performing solvent.³⁸ As it happens, BD3 uses the Cansolv solvent in its carbon capture system.

³² 79 FR 1476; Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3”, DOE/NETL-2015/1723 (July 6, 2015) (“NETL 2015”) (EPA-HQ-OAR-2013-0495-11341 (“NETL 2015”), p. 38.

³³ Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture, Revision 1, DOE/NETL-2011/1498 (“NETL 2013”) (EPA-HQ-OAR-2013-0495-11635) p. 37; 80 FR 64567.

³⁴ NETL 2015 p.17, Exh. ES-4; see also NETL 2013 pp. 41-42.

³⁵ Each study evaluates (individual component by individual component) the following systems: coal sorbent handling, coal preparation and feed, feedwater, boiler and accessories, flue gas cleanup, CO₂ recovery, ducting and stack, steam turbine generator and auxiliaries, cooling water, accessory electric plant, and ash and spent sorbent recovery and handling. See NETL 2013 pp. 109-115; NETL 2015 pp. 103-108.

³⁶ NETL 2013 pp. 65-69 (EPA-HQ-OAR-2013-0495-11635).

³⁷ “Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO₂ Capture Rate in Coal-Fired Power Plants” DOE/NETL-2015/1720, pp. 6-7 (EPA-HQ-OAR-2013-0495-11661); NETL 2015 pp. 59-68.

³⁸ In addition, in considering the updated studies, the EPA was responding to comments, including from Petitioner UARG, urging the EPA to consider costs reflecting actual operation of carbon capture. See 80 FR 64567 (“[t]he EPA used this latest version of the NETL studies not only to assure that it considers the most up-to-date information but also to address public comments criticizing the proposal for relying on out-of-date information”). This fact further obviates the Petitioner's notice and comment concerns. See

Also, as shown in Figure 1 below, the overall estimated costs for the partial CO₂ capture system in the 2015 updated NETL study (presented as the percent increase in cost of the system over an uncontrolled (i.e., no carbon capture) baseline) are virtually identical to those at proposal for the same post-combustion capture system using a different solvent.³⁹ See also 80 FR 64567-69 (other studies and industry information which corroborate NETL cost estimates for CCS). Under these circumstances, the EPA was not obligated to re-notice the cost estimates, or the NETL report itself.

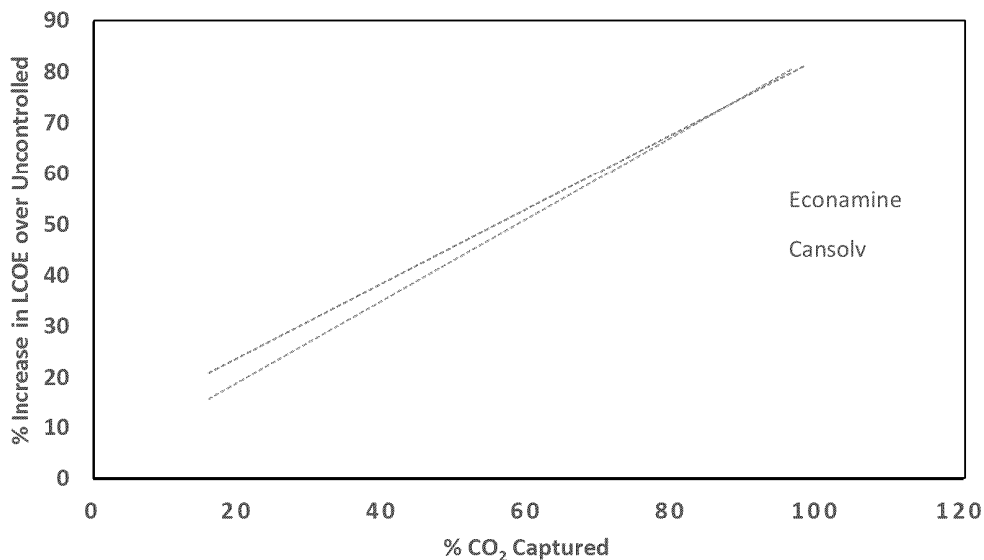


Figure 1. Comparison of Percent Increase in LCOE from Proposal (Econamine solvent) and Final (Cansolv solvent)⁴⁰

UARG nonetheless maintains that these estimated costs don't reflect costs actually experienced by BD3. However, as explained earlier in Section III.A.1, the UARG petition greatly exaggerates the degree of BD3's performance difficulties. Moreover, as also explained

Chemical Manufacturers Ass'n v. EPA, 870 F. 2d 177, 201-02 (5th Cir. 1989) (no further notice and opportunity for comment required where "[t]he EPA did not supplant its economic-impact study, or replace its original data with completely new and different data, but, in response to industry criticisms, updated and expanded one of several data sources"); see also *Community Nutrition Inst. v. Block*, 749 F. 2d 58 (D.C. Cir. 1984) ("Rulemaking proceedings would never end if an agency's response to comments must always be made the subject of additional comments", and this response can take the form of further corroborative scientific studies without triggering a new round of notice and comment) (Scalia, J.).

³⁹ These cost estimates reflect updated estimates for certain common costs between the two technologies, notably labor and material costs.

⁴⁰ Exhibit ES-14 from NETL 2013 ("Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture," Rev 1 (September 19, 2013)), DOE/NETL-2011/1498; and Exhibit A-3 from "Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO₂ Capture Rate in Coal-Fired Power Plants" (June 22, 2015), DOE/NETL-2015/1720 (EPA-HQ-OAR-2013-0495-11661).

above, most of those performance issues relate to ancillary equipment and systems other than those specifically for carbon capture. These are facility-specific issues (e.g., cracks in the amine storage tank) which need not be assumed to be generally applicable. Moreover, the EPA evaluated cost estimates as a range (consistent with the NETL methodology), so that the capital costs could range up to 30 percent higher. 80 FR 64567. The cost estimates that the EPA used in the rule thus account for some measure of potential cost increases.

UARG made particular note of the carbon capture system not capturing sufficient CO₂ for BD3 to meet its contractual obligations, incurring financial penalties and lost revenues as a result. See UARG Petition p. 7. Any costs incurred by SaskPower related to EOR are irrelevant here since the EPA's cost estimates assume geologic sequestration of the captured CO₂ rather than use in EOR operations. 80 FR 64564/2. In any case, UARG exaggerates the extent of SaskPower's difficulties. As again noted above, the company expects to show a profit, even in the short-term, from sales of CO₂ and is presently not only meeting its contractual targets but actually generating more CO₂ than the EOR operator can accommodate.⁴¹ Under these circumstances, UARG's information is not of central relevance to the outcome of the rulemaking since it would not affect the rulemaking's result.

3. Performance Baseline from Which Carbon Capture Is Measured

UARG maintains that the EPA failed to give notice of the uncontrolled baseline emission rate (i.e., the emission rate of an uncontrolled coal-fired boiler) used as the starting point for calculating percent of partial carbon capture needed to meet a standard which is demonstrated at reasonable cost. UARG Petition p. 9 ("The proposed GHG NSPS did not in any way address the baseline emission rate for new SCPC units or analyze the proposed standard's achievability for such units"). Consequently, UARG asserts that it was necessarily impractical to address this issue in comments on the rulemaking, and that the EPA must grant reconsideration to afford opportunity for comment.

UARG's contention is mistaken. At proposal, the EPA indicated that "[a]ccording to the DOE NETL estimates, ... a new SCPC unit using bituminous coal would emit nearly 1,700 lb CO₂/MWh". 79 FR 1468. "SCPC" is an acronym for "supercritical pulverized coal." The exact baseline value used by the EPA at proposal for a supercritical PC boiler using bituminous coal was 1,675 lb CO₂/MWh.⁴² In addition, the EPA recognized that "[t]he emissions would be higher for units utilizing subbituminous coal or lignite ..." 79 FR 1471. The EPA proposed that "highly efficient new generation with partial capture CCS" is the BSER for new fossil fuel-fired boilers and then estimated the cost of applying partial CCS to such a boiler emitting at the proposed emission level. See 79 FR 1476 (Table 6). The EPA then determined in the final rule that an "efficient new supercritical pulverized coal (SCPC) utility boiler implementing partial

⁴¹ Memorandum of conversation between Dr. Nick Hutson (EPA) and Mr. Mike Monca (SaskPower), February 2, 2016; Pet. Exh. G p. 3.

⁴² Exhibit ES-2 from "Cost and performance Baseline for Fossil Energy Plants Vol. 1: Bituminous Coal and natural Gas to Electricity," Revision 2, Report DOE/NETL-2010/1397 (Nov. 2010). The EPA cited to this source when presenting the baseline value ("nearly 1,700 lb CO₂ MWh") in the preamble to the proposed rule. 79 FR 1468 n. 178. We discuss below why an ultra-supercritical PC boiler may also be referred to as a "highly efficient supercritical pulverized coal (SCPC)" boiler.

carbon capture and storage (CCS)” is the BSER for such units and calculated the cost of applying CCS to such a boiler in the same way as at proposal.

The baseline values used by the EPA for the final rule were very similar to the value used at proposal: 1,620 lb CO₂/MWh (for bituminous coal) and 1,737 lb CO₂/MWh (for low rank coal). Final Preamble Tables 8 and 9; Achievability TSD Table 2.⁴³ Moreover, the proposed and final rule use the same methodology to estimate a baseline emission rate. For both the proposed and the final rule, the EPA used baseline estimates drawn from the DOE/NETL “cost and performance” studies for an efficient supercritical PC boiler. Emission estimates for units burning low rank coal were from the original (2011) “Volume 3b: Low Rank Coal to Electricity” report. Emission estimates for units burning bituminous coal were from the original (2011) “Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity” report for the proposal, while the emissions at final were from the updated (2015) version of that report. And, as at proposal, EPA estimated costs for applying partial CCS to a boiler emitting at the specified emission rate. 80 FR 64562 and Table 8.

The EPA thus fully presented all information necessary for comment on this issue at proposal. Specifically, the EPA gave notice of the potential level of performance for a highly efficient, uncontrolled supercritical boiler. Indeed, the EPA received a great deal of public comment on performance of highly efficient boilers without CCS, including quantification of potential levels of performance, confirming that the proposal provided ample notice of the issue.⁴⁴ The petition consequently fails to demonstrate that it was impractical to comment on this issue during the rulemaking.

UARG also fails to demonstrate that the issue it raises is of central relevance to the outcome of the rulemaking. UARG maintains that the baseline is not achieved in practice even by the two best performing plants, the Longview and Turk plants. As a result, according to UARG, the EPA has improperly estimated the rule’s costs since a plant with a higher uncontrolled baseline emission would require a higher level (i.e., a greater percentage) of partial carbon capture in order to meet the emission standard than the level predicted (and costed) by EPA in the final rule. Therefore, UARG claims that the level of the standard must be adjusted accordingly to be less stringent in order to stay within the cost level that the EPA has deemed to be reasonable. Pet. pp. 11-14.

The EPA disagrees with this assessment. First, as the EPA showed in the Achievability TSD, the Turk plant’s best monthly rate (1,725 lb CO₂/MWh) was actually better than the EPA’s assumed uncontrolled emission rate (1,737 lb CO₂/MWh). Achievability TSD p. 6. The plant’s best 12-month average rate (1,753 lb CO₂/MWh) was only slightly higher (by less than 1 percent) than the EPA’s assumed uncontrolled emission rate. Id. And the plant’s worst 12-month average rate (1,817 lb CO₂/MWh) was only 4.6 percent higher than the EPA’s estimated

⁴³ There is a typographical error in the final preamble at 80 FR 64594/3, stating “1,720” instead of the correct “1,620”.

⁴⁴ See RTC comment 6.3-423; see generally id. at comments 6.3-410 through 6.3-424 and 80 FR 64594-95; see also cases cited at n. 39 above, and *National Association of Manufacturers v. EPA*, 750 F. 3d 921, 926 (D.C. Cir. 2014) (notice adequate where petitioners’ comments show that they “had no problem understanding the scope of the issues up for consideration”).

uncontrolled emission rate. *Id.* The Longview Power plant was identified as the best performing supercritical PC plant burning bituminous coal. *Id.* The best 12-operating-month average rate for the plant was only 1.9 percent higher than the EPA's assumed uncontrolled baseline. The highest 12-operating-month average for the Longview Power plant was about 11 percent higher than the EPA's assumed uncontrolled emission – but the Longview Power plant utilizes different steam conditions from those assumed by NETL in the cost and performance report used by the EPA. *Id.* As the EPA found, newly constructed, properly operated, and well maintained bituminous-fired plants that do incorporate the more efficient ultra-supercritical technology would expect to achieve better performance than the Longview Power plant – performance that is consistent with the baseline emissions assumed by the EPA. *Id.*

Further, even assuming that an ultra-supercritical plant (like Turk) could not make modest performance improvements to continue to match its documented monthly performance, the costs of meeting the standards with a slightly increased rate of CO₂ capture would continue to be reasonable. In order to assure that the final standard could be met without imposing unreasonable or exorbitant costs, the EPA finalized a standard with projected costs that are within the range of costs for other non-NGCC generation base load, dispatchable options. 80 FR 64566-567 (explaining why this is a reasonable comparison). Specifically, the EPA finalized a standard with projected costs that are similar in range to a new nuclear unit. The costs for a new highly efficient SCPC EGU emitting at 1,620 lb CO₂/MWh (bituminous coal) and at 1,737 lb CO₂/MWh (low rank coal) with partial capture meeting a standard of 1,400 lb CO₂/MWh are projected to be \$92 – \$117 per MWh for a plant burning bituminous coal and to be \$95 - \$121 per MWh for a plant burning low rank coal. 80 FR 64562, Table 8. These projected costs are well within the ranges projected for a new nuclear unit – estimated to be \$87 - \$115 per MWh by EIA and estimated to be \$92 - \$132 per MWh by Lazard. *Id.* Small changes in the amount of CO₂ that must be captured to meet the final standard would result in small increases in cost, but would still be within the range of costs for a new nuclear plant.⁴⁵

To show this, the EPA evaluated the cost of a new highly-efficient SCPC plant utilizing low rank coal to meet the final standard of performance of 1,400 lb CO₂/MWh-g by implementing partial CCS. The baseline for such a new plant was assumed to range from 1,753 lb CO₂/MWh-g to 1,817 lb CO₂/MWh-g, a range consistent with the Turk facility's "best 12-month average" emission rate and its "worst (or highest) 12-month average emission rate". A comparison of the baseline emission rates and the CCS control levels required to meet the 1,400 lb CO₂/MWh-g standard for the examples used in the final rule as well as for the range of performance for a unit consistent with those exhibited by Turk is shown in Figure 2 below.⁴⁶

⁴⁵ Indeed, as shown in the following Section IV.A.4, even using the cost estimates in UARG Petition Exhibit J developed using their alternative methodology regarding scaling, which increases estimated costs, estimated costs remain within the range of the Lazard cost estimates for a new nuclear plant presented in preamble Table 8.

⁴⁶ This figure essentially adds a new highly efficient SCPC with Turk's "best 12-month average" and with Turk's "worst 12-month average" baselines to Figure 1 from the Achievability TSD. It should be noted that the EPA mentioned the Turk facility at proposal as an example of an ultra-supercritical unit, 79 FR 1468, further undercutting the Petitioner's claims of inadequate notice.

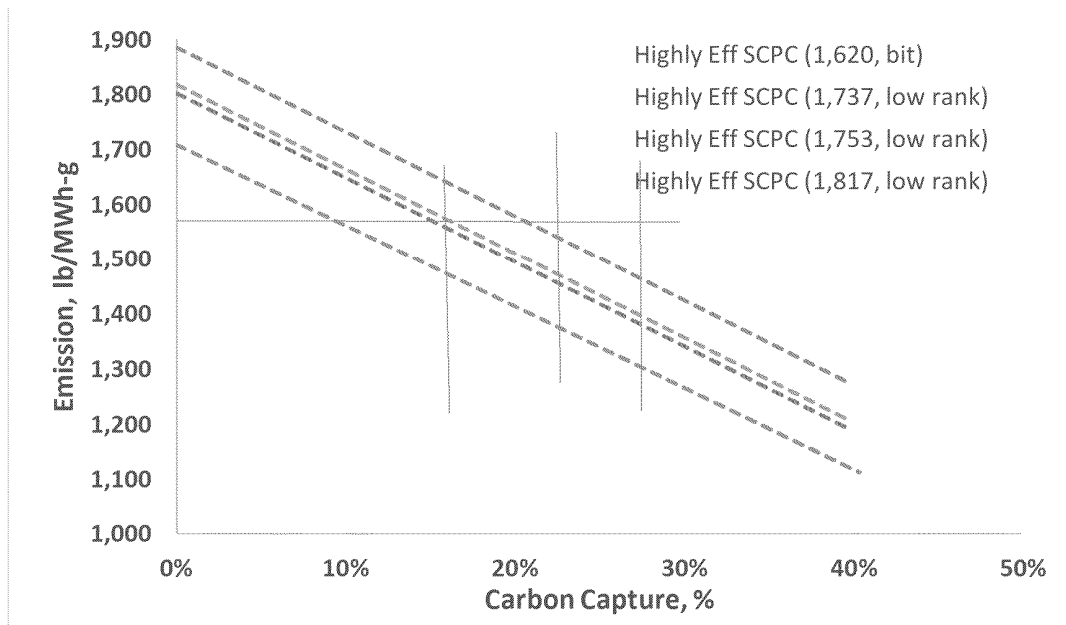


Figure 2. Facility CO₂ emission (lb CO₂/MWh) versus CO₂ partial capture (%)

As can be seen in Figure 2, the “SCPC at 1,753 lb CO₂/MWh-g” (consistent with Turk’s best 12-month average) capture line is essentially the same as the model plant highly efficient SCPC using low rank coal that was estimated in the final rule - requiring about 23 percent capture to meet the 1,400 lb CO₂/MWh-g standard. A new plant exhibiting an emission level of 1,817 lb CO₂/MWh-g (equivalent to Turk’s highest (or worst) 12-month average) would require about 27 percent capture to meet the 1,400 lb CO₂/MWh standard. This information is summarized in Table 1 below.

This Table (which updates Table 2 from the Achievability TSD to include additional information relative to the performance of the Turk facility) shows that a new facility with baseline emissions consistent with Turk’s poorest performing 12-month average would have required approximately 27 percent partial capture to meet the 1,400 lb CO₂/MWh-g standard and the cost of a capture system to achieve that capture level would range from \$98 - 125/MWh, which is in the range of projected cost for new nuclear (EIA at \$87 - \$115/MWh and Lazard at \$92 - \$132/MWh).⁴⁷ Similarly, if the highly efficient new SCPC EGU emitting at 1,620 lb CO₂/MWh were to experience a higher than predicted emission rate consistent with the Turk “worst 12-month average” (i.e., + 5 percent), the unit, with an uncontrolled emission of 1,700 lb CO₂/MWh, would require less capture than the 23 percent that was costed for the new unit using

⁴⁷ The range of Turk’s emission rates (from the best to the worst), coupled with the use of the 12-month rolling average compliance period, cover the range of conditions that new plants may be expected to face. See Achievability TSD, at pp. 1-2 (EPA-HQ-OAR-2013-0495-11771).

low rank coal (and certainly less than the 27 percent capture costed in the Table above for a new unit with the Turk “worst 12-month average” performance).^{48,49}

Table 1. Predicted Cost and CO₂ Emission Levels for a Range of Potential New Generation Technologies

New Generation Technology	Emission lb CO₂/MWh-g	LCOE \$/MWh
SCPC - no CCS (bit)	1,620	76 - 95
SCPC - no CCS (low rank)	1,740	75 - 94
SCPC - no CCS (low rank) – consistent with Turk’s best 12-month average	1,753	75 - 94
SCPC - no CCS (low rank) – consistent with Turk’s worst 12-month average	1,817	75 - 94
SCPC + ~16% CCS (bit)	1,400	87 - 115
SCPC + ~23% CCS (low rank)	1,400	95 - 121
SCPC + ~27% partial CCS (low rank)	1,400	98 - 125
Nuclear (EIA)	0	87 - 115
Nuclear (Lazard)	0	92 - 132
Biomass (EIA)	0	94 - 113
Biomass (Lazard)	0	97 - 116
IGCC	1,430	94 - 120
NGCC	1,000	52 - 86

⁴⁸ The UARG Petition also states that the EPA cost estimates should have included costs for a design (or compliance) margin, since plants are typically designed to perform below the level of a standard to account for performance variability. UARG Petition p. 11; the same point appears in the Petition of the State of Wisconsin at p. 4. The EPA cost estimates already are evaluated as a range and so could be up to 30 percent higher. 80 FR 64567. Including costs for a design margin (if needed) on top of this range would be overly conservative, effectively double counting costs. The 12-month averaging period also accounts for process variability. Id. at 64573.

⁴⁹ UARG quotes the 2015 NETL study as stating, “Actual average annual emissions from operating plants are likely to be higher than the design emissions rates shown due to start-up, shutdown, part-load operation, and performance degradation through maintenance cycles.” UARG Petition p. 11 (quoting NETL (2015), p. 1). The cost analysis just discussed makes clear that plants can adjust to higher baseline emissions by capturing greater amounts of CO₂, but without significantly increasing costs, and, as a result, remaining within the range of overall costs that the EPA determined to be reasonable. The 2015 NETL study quoted by UARG went on make a similar point. See NETL (2015), p. 1 (stating that meeting a required CO₂ emission limit by adjusting for increased emission rates due to, e.g., performance degradation through maintenance cycles, “does not have major cost implications,” except for plants with “low capture rates.” Because the control costs in the NETL study increase linearly starting with capture rates at 16 percent and higher, “low capture rates” below 16 percent are not relevant for this rulemaking.

UARG also overstates when it maintains that the level of carbon capture on which the rule is predicated is EPA's absolute measure of what is cost-effective for the standard. UARG Petition p. 9. In fact, the only costs the EPA did not determine would be reasonable were for full CCS (for either a PC or IGCC unit), and this was because estimated costs "are predicted to *substantially exceed* the costs for other dispatchable non-NGCC generating options that are being considered by utilities and developers". 80 FR 64596 (emphasis added); see also the similar finding at 79 FR 1477. In contrast, capturing an additional small increment (one to four percent) of CO₂ emissions would not result in costs that substantially exceed the other non-NGCC baseload, dispatchable technologies. Indeed, as just shown, the costs of such additional capture would remain within the same range as the cost of new nuclear generating technology. Moreover, the plant would have the ready option of co-firing a small amount of natural gas rather than increasing the rate of CO₂ capture, and thus incur virtually no increased cost. See 80 FR 64564-65. Finally, as noted in the final rule, the EPA expects, in most cases, that utilities and project developers who choose to construct a new coal-fired generating sources, will do so, at least in part, because of revenue opportunities from the sale of captured CO₂. This potential revenue was not factored into the EPA's primary cost analysis and, therefore the costs presented in Table 1 above are likely to be conservative. See 80 FR 64563.

In addition, UARG claimed that it is "nonsensical" for the EPA to base its analysis for *supercritical* boilers combusting low rank coal on projections for *ultra-supercritical* boilers combusting subbituminous coal. Petition p. 11. This objection is purely semantic, and without substance. As the EPA explained at proposal, supercritical coal-fired boilers are designed and operated with a steam cycle above the critical point of water. *Any* boiler that operates above the critical point of water is a supercritical boiler. 79 FR 1468 n. 176. Ultra-supercritical (USC) is a term used to designate a coal-fired power plant design with steam conditions well above the critical point. Id. n. 182. The EPA proposed that "highly efficient new generation with partial capture CCS" is the BSER for new fossil fuel-fired boilers and then finalized that an "efficient new supercritical pulverized coal (SCPC) utility boiler implementing partial carbon capture and storage (CCS)" is the BSER for such units. Subcritical boilers operate using steam conditions below the thermodynamic critical point of water and supercritical boilers operate using steam conditions above the critical point of water. Adjectives such as "ultra" or "advanced" are used to describe SCPC units that are more advanced or more efficient than units operating with steam conditions that are just slightly above the thermodynamic critical point. In other words, an ultra-supercritical PC boiler may also be referred to as a "highly efficient supercritical pulverized coal (SCPC)" boiler.

More important, the issue is not the nomenclature used to describe the highly efficient SCPC boiler, but the quantified level of emissions assumed. As shown above, the level proposed and the level used in the final rule are roughly the same, were developed using the same methodology, and are reasonable. Neither UARG's notice issue nor its semantic objections justify reconsideration.

UARG also claimed that it is arbitrary for the EPA to use baseline emission rates for units burning subbituminous rather than lignite coal to represent the emissions performance of low

rank coals generally. (UARG Pet. at 12) They further noted that, although the EPA grouped these coal types together as “low rank” and treated them identically, the CO₂ emissions of EGUs combusting lignite are substantially different from those of EGUs combusting subbituminous coal and, therefore lignite units would need to capture a greater share of CO₂ emissions, at greater cost, to meet the final standard of 1,400 lb CO₂/MWh-g.

The EPA agrees that the CO₂ emissions of EGUs combusting lignite are different from those of EGUs combusting subbituminous coal. However, the EPA disagrees that a new EGU utilizing lignite would need to capture a greater share of CO₂ emissions at greater cost to meet the final standard of 1,400 lb CO₂/MWh-g because the emissions from units burning sub-bituminous coal and dried lignite are very similar. In the final rule, as UARG noted, the EPA very specifically referred to sub-bituminous and *dried* lignite as “low rank” coal. See, e.g., 80 FR 64513 (“A newly constructed, highly efficient SCPC utility boiler burning subbituminous coal or *dried* lignite will be able to meet this final standard of performance by capturing and storing approximately 23 percent of the CO₂ produced from the facility.”) (emphasis added). UARG contends that lignite drying technologies “are not sufficiently developed or commercially available to provide a viable CO₂ control option” (UARG Petition, Exhibit J at 3-1) and referenced a 2014 analysis prepared by the National Coal Council (NCC)⁵⁰. The EPA disagrees. In fact, the cited reference supports the EPA’s approach. The NCC report states that “[c]oal drying with waste heat *is a commercially available option*, but one that not every plant can effectively deploy. [...] Less improvement would be expected for drying higher coal ranks ... because they tend to be much lower in moisture content than lignite.” (NCC report at 59, emphasis added) The NCC was essentially concluding that coal drying is a commercially available option for lignite, but is not likely effective for higher rank coals because of the lower moisture content. But, the EPA only identified coal drying for use with lignite – not with sub-bituminous or bituminous coals.

While it is difficult, if not impossible, to find real world examples that fully isolate the impact of burning subbituminous versus dried or undried lignite (because other variables including boiler design impact those rates), current emission data confirm the reasonableness of the EPA’s approach. Great River Energy has utilized lignite drying at its Coal Creek (North Dakota) plant with average 2015 emission rates of 2,145 lb CO₂/MWh-g and 2,100 lb CO₂/MWh-g for its units #1 and #2, respectively. These emissions are very similar to those from the sub-bituminous fired units at Colstrip (Montana) that had 2015 emission rates of 2,090 lb CO₂/MWh-g and 2,115 lb CO₂/MWh-g at its units #3 and #4, respectively. In contrast, emission rates in 2015 from a plant burning non-dried lignite, the Antelope Valley (North Dakota) plant, were distinctly higher. It is clear that the emissions from the Coal Creek units are more similar to those from the sub-bituminous fired units at Colstrip (Montana).⁵¹

Finally, UARG claims that the pre-CCS emission baseline should be calculated from the performance of SCPC boilers (i.e., boilers not fully optimized for efficiency) rather than from the

⁵⁰ *Reliable and Resilient: The Value of Our Existing Coal Fleet*, prepared by the National Coal Council (June 2014).

⁵¹ All emissions data are from the EPA’s Air Markets Program Data (AMPD) available at <https://www.epa.gov/airmarkets>

most efficient boilers like the Turk facility. UARG Petition pp. 11-12.⁵² This objection is mistaken, and therefore not of central relevance to the outcome of the rulemaking. The argument is that the EPA “may not focus solely on the best performing units to determine whether an NSPS is achievable”, and that to be achievable, the EPA must demonstrate that the standard can be met under the range of operating conditions that may reasonably occur. *Id.* p. 11. Of course a best system of emission reduction may reasonably reflect performance of optimized control technologies, and if one means of control results in lower emissions, the EPA may reasonably identify that system as a basis for BSER. See 80 FR 64539; see also *Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981) (amount of emissions reduction is obviously relevant in determining a best system). Thus, the EPA may reasonably select as BSER a system that includes a type of boiler designed for optimized operating efficiency.

4. Application of NETL Scaling Methodology

UARG claims that the EPA’s estimates of the capital cost of CCS are unreasonably low. UARG Petition pp. 14-17. Most of the argument reiterates points made in comments to the rulemaking, among them, that the EPA should have placed greater weight on capital costs in its analysis,⁵³ should have used costs of current projects rather than estimated costs, and should have assumed that new projects will incur ‘first-of-a kind’ costs rather than ‘nth-of-a-kind’. None of these issues are new, and all have been addressed by the EPA in the preamble to the final rule and in comment responses. See, e.g. 80 FR 64566-571. Since all of these objections can, and were, raised during the rulemaking, it was obviously practical to do so within the meaning of section 307(d)(7)(B). The EPA is accordingly not granting reconsideration on these objections.

UARG further objects to the methodology by which costs were scaled in the NETL 2015 cost estimates. UARG contends that the estimated capital costs for implementing partial CCS are invalid because they claim that NETL misapplied cost scaling principles to extrapolate costs for partial capture from estimated costs for full capture.

⁵² It is evident that the ultra-supercritical technology is adequately demonstrated. It is deployed both domestically (the Turk plant), and internationally. See Comments of American Electric Power (EPA-HQ-OAR-2013-0495-10938) p. 117, documenting operation or construction of ultra-supercritical units in Poland, Germany, Malaysia, Japan, and Denmark from as early as 1998. Numerous commenters, among them petitioners here, urged its adoption as BSER (rather than partial CCS). Comments of UARG (EPA-HQ-OAR-2013-0495-10938) pp. 69 and 77; Comments of American Electric Power (EPA-HQ-OAR-2013-0495-10938) pp. 114-15; Comments of Alstom (EPA-HQ-OAR-2013-0495-9033) p. 6. The EPA received no significant adverse comment on its statement in the proposal that “[g]eneration technologies representing enhancements in operational efficiency (e.g., supercritical or ultra-supercritical coal-fired boilers or IGCC units) are clearly technically feasible....” 79 FR 1435.

⁵³ The Petition states incorrectly that “[t]he proposed GHG NSPS did not address the capital cost of partial CCS” (UARG Petition p. 14). Estimated capital costs are presented in NETL 2011 at 8-9, 35-7, and then presented for all of the individual study cases at sections 4.2.5 and 4.2.6 and in NETL 2013 at pp. 8, 35-37, and 39 and then presented for all of the individual study cases in the report at section 3.2.4. In the proposal, the EPA relied on the levelized cost of electricity (LCOE) as the cost metric, and LCOE includes capital costs. 79 FR 1435 n. 9. Commenters urged the EPA to consider capital costs as a separate metric, and in the final rule, the EPA did so (along with continued analysis using the LCOE metric), and concluded that this capital cost metric also supported the EPA’s determination that the costs of partial CCS are reasonable. 80 FR 64559-60.

However, both EPA and NETL have clearly presented that the capital cost estimates documented in their reports reflect an uncertainty range of -15 percent to +30 percent - consistent with AACE Class 4 cost estimates (i.e., a feasibility study). The NETL cost estimates are intended to represent the next commercial offering, and relied on vendor cost estimates for component technologies.

As part of the NETL partial CCS studies, it was necessary to estimate the cost of some lower capacity or “scaled down” carbon capture equipment when little or no cost data are available for such smaller equipment. In the 2015 report, NETL specified that a power law with an exponent of 0.6 was assumed to scale 40 percent of the cost of the CO₂ capture system based on the inlet gas volumetric flow to the process and the remaining 60 percent of the cost scaled based upon the captured CO₂ mass flow rate in accordance with Quality Guidelines for Energy System Studies procedures. This power law scaling approach is a very common application of what is referred to as the “six-tenths rule”. In their classic chemical engineering textbook, Peters and Timmerhaus described this rule and its use as follows:

It is often necessary to estimate the cost of a piece of equipment when no cost data are available for the particular size of operational capacity involved. Good results can be obtained by using the logarithmic relationship known as the six-tenths-factor rule, if the new piece of equipment is similar to one of another capacity for which cost data are available. ... However, the application of the 0.6 rule is an oversimplification of a valuable cost concept since the actual values of the cost capacity factor vary from less than 0.2 to greater than 1.0 *Because of this, the 0.6 factor should only be used in the absence of other information.*⁵⁴ (emphasis added)

Following the advice of Peters and Timmerhaus, it is common practice for design engineers to use the 0.6 factor “in the absence of other information” when estimating equipment costs by scaling. The UARG petition acknowledges this normative approach, but maintains that “other information” may justify deviating from it. UARG Petition p. 16 and Exh. J at 4-5 to 4-6.

UARG first suggests that because an EPRI Technical Assessment Guide (“Electricity Supply – 1993 (EPRI TR-102276-V1R7, Vol. 1)) recommends the use of exponents from 0.24 to 0.28 for “power generation equipment”, the cost analysis “*may merit* scaling exponents considerably less than the 0.6 value used by DOE/NETL” for large, capital intensive components such as flue gas absorbers and stripping towers. Exh. J at 4-5 (emphasis added), citing to EPRI Guidance at p. 8-11. UARG then provides an analysis showing how the selection of alternative scaling exponents would affect the projected costs. They also provide a case where a “design margin” is included (i.e., a larger portion of the flue gas is treated as compared to that assumed in the NETL study). In UARG’s “alternative projections”, their example in “Row E” (Exhibit J, Table 4-2), includes an adjustment to the scaling exponents and a “design margin”. They claim that this “alternative projection” – according to their calculation – would add \$6/MWh to EPA’s LCOE projection. They then claim that this “alternative projection” cost invalidates EPA’s conclusion that the cost of partial CCS is reasonable.

⁵⁴ Peters, M.S., and Timmerhaus, K.D.; *Plant Design and Economics for Chemical Engineers*, Third Edition, McGraw-Hill Book Company, New York, NY USA, 1980 (emphasis supplied).

UARG's reference to the EPRI Technical Assessment Guide for power plants is not persuasive. The Guide is for power plant equipment. UARG specifically mentions "foundations, high pressure steam components, and precision equipment such as steam turbines" in their petition. See Exh. J, p. 4-5. As the EPA explained in the rulemaking, a carbon capture system is more similar to a chemical plant than to the equipment traditionally found at a coal-fired power plant. In the post-combustion system, which is the BSER here, liquid solvents are used to separate CO₂ from the flue gas using chemical absorption or chemisorption. In this separation process, flue gas is processed through the CO₂ scrubber and is absorbed by the liquid solvent and then released by heating to form the high purity CO₂ stream. See generally 80 FR 64549 and other sources there cited. This process has nothing to do with generating electricity. It is a chemical process to yield a high purity chemical, in this case, CO₂. Guidance applicable to power plants does not support a deviation from the 0.6 rule-of-thumb to scaling cost estimates for this chemical plant type of process. In fact, Schnelle, et al., recommend the use of the six-tenths factor rule for scaling air pollution control technologies:⁵⁵

A key consideration for equipment costing is the economy of scale. In general, the cost of equipment does not double as the size of the equipment doubles. In fact, the general cost relationship for equipment as a function of the equipment capacity is referred to as the *six-tenths factor rule*

UARG also claims that the NETL cost estimates are invalid because they applied the power-law scaling correlation (i.e., the 0.6 rule-of-thumb) for mass rates of CO₂ processing below the range of 445,000 to 689,000 lb/hr, claiming that the NETL Quality Guidelines provide that the power law scaling correlation is valid only when used within that range. Petition Exh. J at 4-6. However, the NETL guidelines do not say that. Instead, the NETL guidelines state that "[t]here are limitations on the ranges that can accurately be addressed by the scaling approach. ... Care should be taken in applying the scaling factors when there is a large percentage difference between the scaling parameters."⁵⁶ The NETL guidelines thus do not provide that use of the power law correlation is invalid outside the recommended ranges – but, rather, they instruct users to take care when applying the cost correlation in those instances. Similarly, Peters and Timmerhaus advise that:

In general, the cost-capacity concept should not be used beyond a tenfold range of capacity, and care must be taken to make certain the two pieces of equipment are similar with regard to type of construction, materials of construction, temperature and pressure operating range, and other pertinent variables.

A CO₂ flow rate that is "beyond a tenfold range of capacity" would be one that is less than 44,500 lb CO₂/hr and none of the NETL costing evaluations are less than that amount. In addition, the EPA did "[take] care ... to be certain the two pieces of equipment are similar" because partial CCS involves the same equipment as full capture.

⁵⁵Schnelle, K.B.; Dunn, R.F.; and Ternes, M.E.; *Air Pollution Control Technology Handbook, Second Edition*, CRC Press, Taylor & Francis Group, LLC, Boca Raton, FL (2016). (emphasis in the original)

⁵⁶DOE/NETL *Quality Guidelines for Energy System Studies: Capital Cost Methodology* (DOE/NETL – 341/013113 at p. 18 (attached as Exh. K to the UARG Petition)).

Moreover, even if the EPA were to accept UARG's alternative analysis – which we do not – we would not reach the conclusion that the resulting re-estimated costs are unreasonable. First, even UARG acknowledges that their alternative costs still fall within the LCOE ranges reported for nuclear (Nuclear/Lazard)⁵⁷ and are therefore reasonable using the rationale applied in both the proposal and in the final rule. Second, the UARG analysis fails to acknowledge the uncertainty that has already been included in the NETL cost analysis. As mentioned earlier, the capital cost estimates documented in the reports reflect an uncertainty range of -15 percent to +30 percent - consistent with AACE Class 4 cost estimates (i.e., a feasibility study). Third, as was also mentioned earlier, even if UARG's alternative projections were convincing, they have again incorrectly assumed that the EPA has defined a “break point” of cost reasonableness. That is not the case. The EPA promulgated a final standard of performance with a projected cost range that is consistent with projected cost ranges for other competing generation technologies. However, the EPA did not find – nor ever suggest – that costs above those ranges are unreasonable or exorbitant. In fact, the EPA only found that because the costs of new generation technologies implementing *full CCS* were *significantly* beyond the projected cost for competing generating technologies, full CCS was not the best system of emission reduction. Finally, cost increases could be either ameliorated or eliminated by co-firing with a minor amount of natural gas, as noted above. See generally 80 FR 64564-565.

Overall, UARG has not convincingly established why the costing exponents that they have chosen for their “alternative projections” are preferred over the very common “rule-of-thumb” 0.6 exponent that NETL adopted in the absence of better information. UARG has also not convincingly established that the use of the power law cost correlation is “invalid” when applied beyond the capacity ranges recommended by NETL. Further, even if the EPA were to adopt UARG's “alternative projection”, the EPA is still not convinced that the resulting costs are unreasonable or exorbitant. Therefore, the EPA does not find these issues to be of central relevance and is denying the petition for reconsideration.

5. Inclusion of the Heat Input from Duct Burners in the Definition of “Base Load Rating”

The EPA is denying UARG's petition for reconsideration of the final rule's definition of “base load rating.” While the EPA agrees that it was impracticable for UARG to raise its objection during the public comment period, UARG has failed to explain how its objection is of central relevance to the outcome of the final rule. Contrary to UARG's suggestion, a petitioner seeking reconsideration must demonstrate that its “objection” is of central relevance, not merely that the objection discusses an “issue” of central relevance. UARG Pet. at 17 (“The issue is centrally relevant to the Rule because it implicates the fundamental question of what units are subject to the GHG NSPS.”). In fact, the EPA's decision to include the heat input from duct burners in the definition of “base load rating” was not only reasonable, but advantageous to industry and its members, including UARG. The final definition provides certain stationary combustion turbines with greater flexibility to generate and sell to the grid larger amounts of electricity without triggering more stringent regulatory requirements. Finally, no more than a few, if any, combustion turbines will become subject to the rule's requirements as a result of the

⁵⁷ UARG's “alternative projection” for the “SCPC + ~16% CCS (bit)” case increases the cost from \$92 - \$117 per MWh to \$98 - \$123 per MWh. The estimated cost for a new nuclear unit, as estimated by Lazard, is \$92 - \$132 per MWh.

change, and the record demonstrates that even those few turbines will be able to achieve the standard of performance.

At the outset, UARG does not meet its burden of demonstrating central relevance. UARG objects to the inclusion of the heat input from duct burners in the definition of “base load rating” by noting alleged inconsistencies with the proposed rule and the criteria-pollutant NSPS for stationary combustion turbines. However, UARG does not explain why these alleged inconsistencies, which (as explained below) exist for good reason, are problematic. UARG also cites to comments it submitted on the proposed emission guidelines for existing fossil-fuel-fired EGUs, but the citation provided consists of an irrelevant discussion of why Building Block 1 (i.e., heat rate improvements) is allegedly unachievable for *coal-fired EGUs*, not combustion turbines.⁵⁸ The EPA reviewed UARG’s comments on the emission guidelines in full,⁵⁹ but the only mention of duct burners is in a similarly irrelevant discussion of why Building Block 2 would allegedly require existing natural gas combined cycle (NGCC) units to fire their duct burners on a continuous basis.⁶⁰ The inclusion of the heat input from duct burners in the definition of “base load rating” relates to the final rule’s applicability requirements, however, not the achievability of the BSER. Because UARG has not provided the EPA with sufficient information to evaluate its conclusory objection to the definition of “base load rating” as it applies to stationary combustion turbines, the EPA finds that UARG’s objection is not of central relevance to the outcome of the rule.

In any event, the definition of “base load rating” in the final rule is reasonable for several reasons. First, the definition is consistent with other changes the EPA made to the proposal. The proposed rule included subcategories for small and large stationary combustion turbines, consistent with the criteria-pollutant NSPS.⁶¹ At the time of proposal, the EPA’s rationale for subcategorizing based on size was that NGCC units that use aeroderivative combustion turbine engines were less efficient than NGCC units that use large industrial frame combustion turbine engines. 79 FR 1486. Specifically, the small subcategory covered units with a heat input of 850 MMBtu/h or less, including both aeroderivative and smaller industrial frame combustion turbine engines. The large subcategory covered units larger than 850 MMBtu/h, all of which are large industrial frame combustion turbine engines.

At proposal, the EPA defined “base load rating” as “100 percent of the manufacturer’s design heat input capacity of the combustion turbine engine at ISO conditions using the higher heating value of the fuel (heat input from duct burners is not included).” 79 FR 1509. If the EPA had included the supplemental heat input from duct burners in the definition of “base load rating” at proposal, some aeroderivative and small industrial frame combustion turbines likely would have exceeded the 850 MMBtu/h threshold and become subject to the more stringent

⁵⁸ See Comments of the Utility Air Regulatory Group on the United States Environmental Protection Agency’s Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule at 212 (Dec. 1, 2014), EPA-HQ-OAR-2013-0602-22768.

⁵⁹ Even though the EPA undertook such a review here, the EPA notes that the CAA does not require the agency to search through a petitioner’s previously-filed comments to account for incorrect citations.

⁶⁰ Comments of UARG at 206.

⁶¹ 40 CFR Part 60, Subpart KKKK.

standard for large units, which was based on the supposedly more efficient operation of large industrial frame combustion turbines.

In response to comments, however, the EPA eliminated the proposed size-based subcategories in the final rule and, consistent with a noticed alternative approach, 79 FR 1459-61; 79 FR 34979-81, established a single emission standard for all natural gas-fired combustion turbines operating at base load. The EPA concluded that size-based subcategories were not appropriate for a CO₂ emission standard because (1) no clear cut-point exists between “small” and “large” units; (2) size-based subcategories could unduly influence the development of future NGCC offerings; (3) actual operating and design data showed a relatively weak correlation between turbine size and CO₂ emission rates, with the emission-rate variability among similar size units far exceeding any variability that could be attributed to a difference in size; (4) most existing small units had already demonstrated emission rates below the proposed emission standard for large units; and (5) the lower design efficiencies of some small units were primarily related to model-specific design choices in the turbine engine and heat recovery steam generator, not inherent limitations in the ability of small units to achieve comparable efficiencies to large units. 80 FR 64608-09. By eliminating the size-based subcategories, the EPA’s prior concern—that including the heat input from duct burners in the definition of “base load rating” would cause some aeroderivative and small industrial frame combustion turbines to be included in the large unit subcategory—was no longer an issue.

Second, the final definition of “base load rating” actually benefits industry. As the EPA explained in the final rule, the definition of “base load rating” includes the heat input from duct burners to accurately account for the potential electric output of the affected unit. 80 FR 64608. This definition complements both the finalized operations-based subcategorization approach and the exemption for industrial combined heat and power (CHP)⁶² facilities.

In regards to the former, the final rule established non-base load and base load subcategories for natural gas-fired stationary combustion turbines. The base load subcategory is subject to an output-based emission standard of 1,000 lb CO₂/MWh-g that reflects modern, efficient NGCC technology. The non-base load subcategory, on the other hand, is subject to a less-stringent input-based emission standard of 120 lb CO₂/MMBtu that reflects the use of clean fuels. The distinction between the base load and non-base load subcategories is based on an affected unit’s net-electric sales and potential electric output. Potential electric output is determined, in part, by multiplying a unit’s design efficiency by its base load rating. At a given design efficiency, units with a higher base load rating will have a higher potential electric output. The higher a unit’s potential electric output, the more electricity that unit can sell to the grid before being classified as a base load unit subject to the more stringent output-based standard. In other words, by including the heat input from duct burners in the definition of “base load rating,” the EPA increased the amount of electricity that a non-base load unit with duct burners can sell to the grid. This result favors industry, and UARG has not objected to it.

⁶² “Combined heat and power unit or CHP unit, (also known as ‘cogeneration’) means an electric generating unit that use[s] a steam generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.” 40 CFR 60.5580.

In regards to CHP facilities, the final applicability criteria are not intended to cover industrial CHP units that are primarily intended to provide useful thermal output (e.g., steam) to a host facility. 80 FR 64533-35. To differentiate between industrial and utility CHP units, the EPA used a similar approach to the one used to distinguish between base load and non-base load units, i.e., a comparison between net-electric sales and potential electric output. As described previously, potential electric output is determined, in part, by multiplying a unit's design efficiency by its base load rating. CHP units often include duct burners to satisfy the steam demands of the host facility. Thus, the inclusion of the heat input from duct burners in the definition of "base load rating" means that CHP units with duct burners will have a higher base load rating and a higher potential electric output than they would otherwise. The result is that industrial CHP units with duct burners can sell more electricity to the grid without becoming subject to the final rule's requirements. This result also favors industry, and UARG has not objected to it.

Third, few, if any, new NGCC units are likely to become subject to the final rule's requirements as a result of the change to the proposed definition,⁶³ and even these units will not be disadvantaged because they will be able to achieve the 1,000 lb CO₂/MWh-g standard. There are two types of duct burners: (1) small duct burners designed to recover lost output during periods of high ambient temperatures and (2) large duct burners designed to create additional output during all types of conditions.⁶⁴ Combustion turbines combust less fuel when ambient temperatures are higher than ISO⁶⁵ conditions (288 Kelvin (15 °C), 60 percent relative humidity, and 101.3 kilopascals pressure), reducing electric output. Relatively small duct burners (e.g., less than 5 percent of the potential heat input of the affected unit) are often used to make up this shortfall. Owners and operators typically only run these smaller duct burners during periods of peak summer demand, when ambient temperatures are high. To calculate a unit's base load rating, however, an owner or operator must determine the amount of fuel that the unit can combust at steady state and ISO conditions.⁶⁶ Because the base-load-rating calculation is based on the affected unit's operation at ISO conditions, not ambient conditions, the heat input from this type of smaller duct burner will not affect the calculation.

In contrast, large duct burners (e.g., greater than 5 percent of the potential heat input of the affected unit) are used to create additional steam turbine output at ISO conditions, meaning the final definition of "base load rating" could potentially affect combustion turbines equipped with this type of burner. However, (where no exemption applies) the final rule only applies to units that (1) have a base load rating greater than 250 MMBtu/h of fossil fuel and (2) serve a

⁶³ For example, UARG could not identify any example existing stationary combustion turbines that would be impacted by the change. See Utility Air Regulatory Group, Petition for Reconsideration of EPA's "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64,662 (Oct. 23, 2015), at 17 (Dec. 22, 2015).

⁶⁴ Backlund, Jon and Froemming, Jim; *Thermal & Economic Analysis of Supplementary Firing Large Combined Cycle Plants*, <http://www.coen.com/library/technical-papers/thermal-economic-analysis-of-supplementary-firing-large-combined-cycle-plants/>.

⁶⁵ ISO refers to the "Industrial Organization for Standards." See <http://www.iso.org/iso/home.html>.

⁶⁶ "Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU *at ISO conditions*." 40 CFR 60.5580 (emphasis added).

generator capable of selling greater than 25 MW of electricity to the grid. 40 CFR 60.5509(a)(1)-(2). Most new NGCC units will have a base load rating *greater* than 250 MMBtu/h even *without* the heat input from large duct burners. In fact, the smallest NGCC units capable of meeting the 25 MW criterion will have a heat input rating of approximately 200 MMBtu/h (not including the heat input from duct burners).⁶⁷ The record for the final rule shows that NGCC units with a base load rating of only 190 MMBtu/h can comfortably achieve the final rule's 1,000 lb CO₂/MWh-g standard with a design compliance margin⁶⁸ of 11 percent.⁶⁹ Therefore, while a handful of smaller NGCC units might exceed the 250 MMBtu/h threshold and become affected units once the heat input from their duct burners is accounted for, even these units will not be disadvantaged. As a result, UARG's conclusory objections are unfounded, and the EPA is denying reconsideration on this issue.

6. Objections Related to Identity of Reporting Entities

UARG's final objection relates to the mechanics of electronic reporting. UARG complains that the final rule restricts the person submitting reports to a "Designated Representative", whereas the proposal would have allowed anyone qualifying as an "owner or operator" to submit reports. UARG claims it had no notice of this possibility, and that there are substantive reasons that a designated representative should not submit reports. UARG Petition p. 18.

UARG has not met either of the requirements for granting reconsideration on this issue. The EPA proposed that owners/operators of affected EGUs submit reports. 80 FR 1452. UARG submitted comments on the issue, noting among other things that the proposal was meant to be consistent with e-reporting under the acid rain program, and that under that program a "designated representative" files reports. UARG Comments p. 194. The comment continued that under various applicable rules, not all designated representatives are owners/operators, and that EPA should deal with this issue in the final rule so that "any individual who meets the definition of 'owner or operator'" can certify and submit reports. *Id.* p. 195. The EPA responded in the final rule by allowing reports to be submitted by a designated representative, a person appointed as alternate designated representative, or a person authorized by either of these. Any of these can be an owner/operator. Section 60.5555(d) and (e); see also RTC 12.4-6 indicating that the final rule was being clarified to address UARG's comment.

It is clear both from EPA's proposal and from UARG's comment that it had adequate notice of the question of who reports, and indeed, their comment directly addressed the issue of the relationship between owner/operator and designated representative. Moreover, this issue is not of central relevance to the rule, since it deals with a nuance of rule implementation, not with

⁶⁷ While there is sufficient oxygen in the combustion turbine engine exhaust to theoretically support duct burners with a maximum heat input value greater than the combustion turbine itself, for practical reasons, the duct burners used in electric-only NGCC units are generally limited to approximately 20 percent of the heat input of the affected unit. Newell, Samuel A., et al.; *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants* in PJM with June 1, 2018 Online Date, <https://www.pjm.com/~media/documents/reports/20140515-brattle-2014-pjm-cone-study.ashx>.

⁶⁸ A compliance margin is the difference between a unit's performance capability and the actual standard of performance.

⁶⁹ Gas Turbine World Efficiency Combined Cycle Efficiency, EPA-HQ-OAR-2013-0495-11888.

whether the standard of performance reflects a best system of emission reduction which is adequately demonstrated.

In any case, UARG's objection lacks substantive merit. UARG reiterates that there are distinctions between the acid rain and NSPS programs such that only owner/operators should report under the NSPS program. Petition pp. 18-19. Even assuming this is the case, the final rule obviates UARG's concern because it allows owners/operators to report if affected EGUs wish to do so. Specifically, the rule provides that for affected EGUs subject to the acid rain program, either a designated representative, authorized designated representative, or person authorized by either of these, can report. 60 CFR section 60.5555(d). Thus, even if they are not already one and the same, a designated representative or authorized designated representative can in turn authorize the owner/operator⁷⁰ to file. UARG notes that section 60.5555(d) begins by stating that the report "shall be submitted by", and misreads the provision to assume that this means only designated representatives can file. UARG Petition p. 19. Section 60.5555(d)(3) makes clear that a designated representative can in turn authorize any other entity, including an owner/operator, to file.

Identical provisions apply in the case of affected EGUs not subject to the acid rain program: filing can be done by a designated representative, authorized designated representative, or an entity authorized to file by the designated representative. Section 60.5555(e).

Since this objection does not satisfy any of the requirements in the Act for granting reconsideration, the EPA is denying it. Moreover, since the final rule allows owner/operators to file, it appears to provide UARG with all the relief it seeks on this issue so that there is no basis for objection.

B. Response to AEP Petition

AEP essentially objects to the EPA's characterization of its experience in retrofitting one of its plants, the Mountaineer Plant (New Haven, WV), with partial CCS in a demonstration project. The EPA viewed (and views) that experience as providing support for partial CCS being an adequately demonstrated technology. AEP claims that it and others submitted extensive comment that EPA failed to adequately address.

The EPA cited to AEP's own figures in finding that the project achieved CO₂ capture rates on the slip stream of from 75 to 90 percent. The EPA also cited AEP's own FEED report⁷¹ on how the demonstration project could be scaled up to full scale capture. 80 FR 64552, 64557; see also 79 FR 1436 and 1475 (discussing the Mountaineer project at proposal). The EPA also quoted AEP Chief Executive Officer's own praise of the project's performance: "we feel that we have demonstrated to a certainty that the carbon capture and storage is in fact viable technology for the United States and quite honestly for the rest of the world going forward." (80 FR 64556) The EPA likewise quoted Alstom senior Vice President Joan MacNaughton's 2011 public statement that "[t]he Validation Plant at Mountaineer demonstrated the ability to capture up to 90

⁷⁰ "Owner/operator" is defined in the general provisions at 40 CFR 60.2. The definition is capacious and does not limit the ability of a designated representative to delegate filing authority to an owner/operator.

⁷¹ FEED = Front End Engineering Design

percent of the CO₂ from a stream of the plant's emissions. The technology works." RTC Chapter 6 at 6-152. (Alstom was a partner in the demonstration project, which used its chilled ammonia carbon capture technology.)⁷²

AEP did indeed submit comments in this rulemaking maintaining that the Mountaineer project did not demonstrate that partial CCS is BSER. Among other things, those comments maintained that the project was too small in its scale to demonstrate that partial CCS is adequately demonstrated at commercial scale, and that there were extensive cost overruns on the project, many of them attributable to difficulties in siting monitoring wells used to assure integrity of the CO₂ sequestration area. Comments of AEP (May 8, 2014) pp. 80-83. The EPA responded to all of these comments, noting among other things that both AEP's own FEED study and the NETL studies set out in point-by-point, system-by-system detail how the capture technology could be scaled up to full-scale⁷³, why the costs at the project were not indicative of costs at a new facility (for example, since the project was a retrofit, the project presented siting issues (including siting for monitoring wells) that could be avoided for a new plant)⁷⁴, and generally why partial CCS is not exorbitantly costly.⁷⁵

AEP does not maintain (nor could it do so plausibly) that it lacked notice of the issue to which it now objects. The EPA also believes that the agency reasonably characterized the performance of the Mountaineer project, reasonably responded to AEP's public comments, and accurately quoted and interpreted the public statements of AEP and Alstom executives characterizing the performance of the Mountaineer project. See, e.g., RTC response 2.1-235. The project does provide strong support for the technical feasibility of partial CCS, including at commercial scale. Moreover, the costs incurred at the project are not indicative of costs for a new source given that the project is a retrofit. Consequently, in addition to being untimely, AEP's objection is not of central relevance to the outcome of the rulemaking, and the EPA is therefore denying the petition to reconsider.

AEP also maintains that the record contains no information showing that Boundary Dam Unit 3 is capable of achieving the promulgated standard since it had operated for less than one year at the time of promulgation.⁷⁶ The EPA's basis for finding that the standard is achievable is fully set out at 80 FR 64573-74 and in the Achievability TSD. The EPA gave ample notice that it regarded Boundary Dam as a plant preparing to utilize full scale CCS, and noted that its design level and reported initial performance were well in excess of the rate of carbon capture on which the standard of performance is predicated. 79 FR 1435; 80 FR 64549-50. AEP's objection

⁷² See also RTC response 6.3-107 (more quotes from AEP and Alstom executives praising performance of CCS); id. at response 6.3-320 (Alstom Senior Vice President MacNaughton states publicly that "coal with CCS is cost competitive with the cost of electricity generated by other low- or no-carbon energy sources"; the full text of the press release from Alstom Vice President MacNaughton is at EPA-HQ-OAR-2013-0495-11320).

⁷³ See, e.g. Final Preamble section V.G.3; RTC response 6.3-23 at p. 6-17.

⁷⁴ See, e.g. 80 FR 64573; RTC responses 6.3-93, 6.3-247 (at pp. 150-151), 6.3-259 (at p. 167), 6.3-272 (at p. 183).

⁷⁵ RTC response 6.3-286.

⁷⁶ UARG raises a similar point at p. 11 of its Petition. The exhibits to UARG's own petition show that BD3 met the U.S. standard in its initial year of operation. See III.A.1 above.

therefore fails to demonstrate that there was lack of opportunity to comment during the rulemaking or that the objection is of central relevance to the rulemaking's outcome.

C. Response to Ameren Petition

Ameren's petition deals virtually in its entirety with objections to the section 111(d) emission guidelines. The petition states correctly that the section 111(b) NSPS is related to the emission guidelines, but the only specific objection raised to the section 111(b) standards is a claim that partial CCS is not adequately demonstrated, an issue on which there was obvious opportunity to comment during the rulemaking. Since the petition states no legitimate grounds for granting reconsideration, the EPA is denying it.

D. Response to State of Wisconsin Petition

The State of Wisconsin largely reiterates comments it made during the rulemaking, but claims that the EPA did not adequately respond to them. These include comments regarding achievability of the proposed NSPS; consistency of the standard with individual BACT determinations (including a BACT determination made by the State Of Wisconsin for the Elm Road power plant); CCS' status as an "emerging technology" that cannot be BSER; and lack of geologic storage capacity in Wisconsin, which the State asserts puts Wisconsin at a competitive disadvantage. Wisconsin Petition Attachment 1 at 1. The EPA in fact addressed all of these issues, and Wisconsin's comments regarding them, in the rulemaking. See e.g., RTC comment responses 9.5-2, 6.3-237, 6.3-291, 6.3-332 and 80 FR 64631-32 (responses relating to BACT determinations and choice of partial CCS as BSER)⁷⁷; 2.1-147, 2.1-149, 2.1-157, 2.1-238, 6.3-23 (responses relating to "emerging technology"); 6.3-60; 6.3-72, 6.3-84, 6.3-99, 6.3-100, 6.3-251,

⁷⁷ The State asserts that its 2012 determination that full CCS was not BACT for the Elm Road coal fired plant undercuts EPA's technical determination that partial CCS is BSER for new plants. This assertion lacks a reasoned basis. First, individual state BACT determinations, while relevant, do not constrain federal technical determinations in the different context of section 111 standards (80 FR 64631). Second, this particular BACT determination is not properly comparable to the new source standard. The determination involved application of CCS to an existing facility, not to a new source. Thus, the BACT determination was triggered by an existing source's request to burn sub-bituminous rather than bituminous coal. The State determined that although full CCS was a technically feasible control technology for CO₂, the technology was economically infeasible for two reasons: there was insufficient land available at the existing site to sequester captured carbon, and the nearest sequestration site was out of state, necessitating very high transport costs. See generally, "ANALYSIS AND PRELIMINARY DETERMINATION FOR THE CONSTRUCTION PERMIT FOR THE PROPOSED MODIFICATION OF TWO COAL FIRED POWER BOILERS FOR Wisconsin Electric Power Company, d.b.a WE ENERGIES-OAK CREEK STATION, LOCATED AT 11060 S CHICAGO RD., OAK CREEK, MILWAUKEE COUNTY, WISCONSIN" Construction Permit No.: 12-SDD-047 (October 22, 2012), pp. 13-14. Thus, this determination is consistent with the EPA's determination in the section 111(d) emission guideline rulemaking and the section 111(b) rulemaking that full CCS is not BSER for existing or modified power plants. The determination in the permitting proceeding also is at odds with the State's position here that CCS is not a technically feasible technology. See also RTC Response 6.3-291 where the EPA gave a similar response to the similar comment regarding a BACT determination for an Iowa facility.

2.1-228 and 80 FR 64549-54, 64556-57, 64575-82 (responses relating to availability of sequestration capacity and demonstration of partial CCS technology). The petition thus fails to state any grounds requiring EPA to reconsider any of these issues.

The State also maintains that EPA miscalculated costs relating to transport of captured CO₂ for Wisconsin new sources, largely because the EPA cost estimates assume transport for 62 miles (100 km) rather than the 270 miles Wisconsin sources would need to use. Wisconsin Petition Attachment 1 pp. 1-2 and n.9. In fact, a New Source Performance Standard is developed on a nationwide, not state-by-state basis, and the EPA's evaluation of costs was reasonable. The record shows, and indeed Wisconsin does not contest (or even address) that 95 percent of the largest CO₂ sources are within 50 miles of a potential storage reservoir. The State also does not contest or even address the other potential compliance paths noted in the administrative record: CO₂ storage can be provided by enhanced oil recovery (EOR); a new source can be sited out-of-state proximate to a sequestration site (for example, in Illinois, the example given in the State's petition) and still provide electricity via 'coal-by-wire' arrangements. These arrangements are documented for distances considerably greater than the 270 miles the State refers to in its Petition. See 80 FR 64572, 64579-81, 64582-83; RTC comment responses 6.3-251; 6.3-277; responses in unit 6.3.4.

In addition to a coal-by-wire compliance alternative, the EPA noted that coal plants could co-fire natural gas and meet the standard without the need for CCS (partial or otherwise). 80 FR 64564. Wisconsin challenges this determination in its Petition, although it (properly) does not claim that it lacked opportunity to comment on the issue, or that its objection is of central relevance to the outcome of the rulemaking. Wisconsin asserts that co-firing at rates of 30 percent or higher is not an adequately demonstrated technology and so this compliance path may not exist for some sources. Specifically, the Petition states that "EPA's own reference documents show that co-firing natural gas up to 30 percent (on a heat input basis) has not moved beyond the design/pilot state; therefore co-firing gas at 40 percent has not been adequately demonstrated". Wisconsin Petition Attachment 1 p. 2, referring to the EPRI technical report "Gas Cofiring Assessment for Coal Fired Utility Boilers" cited by the EPA at 80 FR 64564 n. 288 ("EPRI Cofiring Assessment"). This contention is mistaken. The EPA found that natural gas co-firing rates of up to 40 percent could be achieved by using a combination of natural gas reburning and supplemental gas firing. 80 FR 64564/3. The EPRI Cofiring Assessment indicates that these rates of co-firing are demonstrated and achievable. EPRI Cofiring Assessment at pp. 2-4, 2-5, 2-35. The petition mistakenly confused these well-established technologies, which are the ones the EPA evaluated and costed, with a different technology, coal/gas co-firing burners (discussed in unit 2.6 of the EPRI Cofiring Assessment) (See, e.g., EPRI Cofiring Assessment unit 2.6 at pp. 2-40 to 41; Executive Summary p. 1; Executive Summary p. xvii "The largest number of applications and the longest experience time is with reburning and supplemental gas firing."). Because these co-firing techniques introduce natural gas at different locations - in a boiler's primary combustion zone (supplemental gas co-firing) and in the upper regions of the primary furnace above the primary coal combustion zone (reburning techniques) - they can be implemented in combination.

The State of Wisconsin also argued that coal boiler operators would likely need to fire even more than 40 percent natural gas to be in compliance with the final standard, since 1) they need to have a sufficient compliance margin below the standard, and 2) the EPA's assumed base

rate of 1,618 lb CO₂/MWh-g is lower than what has been achieved in practice. There is no technological reason that a new boiler cannot be designed to accommodate an increased level of natural gas co-firing (there is at least one existing EGU with the capacity to fire 100 percent coal or 100 percent natural gas – and to co-fire combinations of the two). Further, even if a new EGU needed to (or chose to) co-fire more than 40 percent natural gas to meet the standard of performance, the cost would be well within the range of costs that the EPA found to be reasonable (See 80 FR 64565, Table 9).

The petition also maintains that EPA cannot consider natural gas co-firing as an alternative compliance path in any case because doing so impermissibly redefines the source. Wisconsin Petition Attachment 1 p. 2. This issue was raised in public comment and the EPA has already responded. RTC Comment and Response 2.1-103; 2.1-213; 2.1-214; 2.4-6. Thus, the objection is untimely.

It also lacks central relevance. In brief, redefining a source is a concept that has developed exclusively in the context of the Prevention of Significant Deterioration (PSD) program, under different statutory criteria. PSD determinations are case-by-case preconstruction requirements that require the incorporation of the “best available control technology” (BACT) at the time of construction of a new major emitting facility or as part of a major modification⁷⁸ of an existing facility. Because BACT applies at the preconstruction stage on a case-by-case basis and generally requires the installation of control technology, it is appropriate, though not required, for a permitting authority to limit the scope of BACT to avoid frustrating the fundamental purpose and to consider the inherent design of such projects on a case-by-case basis.

Under the PSD program, there is no absolute prohibition against redefining the source,⁷⁹ but rather an EPA-developed policy of caution concerning fundamentally redefining the source and disrupting the basic business purpose of a project in the context of BACT determinations.⁸⁰ The State’s argument consequently fails even if one were to accept its logic that the concept applies to establishing section 111(b) standards of performance.

The State is in fact in error in its contention that the redefining the source concept is even relevant in the section 111(b) context. Under section 111(b), the Administrator identifies a list of adequately demonstrated control options, selects the best of those control options after considering cost and other factors, then selects an achievable limit for the category through the application of the BSER across the industry. The BSER for purposes of section 111(b) is not limited to technology that can be built into a specific source because affected sources have already been constructed. Rather, it is generally based on pollution control systems that can be implemented by a new source. A best system of emission reduction certainly can entail some

⁷⁸ Note that the requirements of a NSR “modification” are distinct from the standards for “modifications” finalized under CAA section 111(b).

⁷⁹ PSD and Title V Permitting Guidance for Greenhouse Gases at 27 (March 2011) (“EPA does not interpret the CAA to prohibit fundamentally redefining the source and has recognized that permitting authorities have the discretion to conduct a broader BACT analysis if they desire”); *In re Knauf Fiberglass*, 8 E.A.D. 121, 136 (EAB 1999) (“redefinition of the source is not always prohibited”).

⁸⁰ *In re Prairie State Generating Company*, 13 E.A.D. 1, 15-28 (EAB 2006).

measure of fuel substitution.⁸¹ Moreover, natural-gas co-firing here is an alternative compliance path noted by EPA, but not part of the Best System of Emission Reduction, see 80 FR 64564, so any analogy with the BACT process fails in any case.

Indeed, as EPA has already explained, natural gas co-firing has been used for years as a mechanism for reducing air pollution from coal-fired boilers. 80 FR 64564; see also 79 FR 1471. Consequently, the EPA reasonably determined that natural gas co-firing could constitute an alternative compliance path for meeting the 1,400 lb CO₂/MWh standard of performance, that this alternative compliance pathway is generally available and obviates issues of access to geologic sequestration and EOR capacity, and that the statute does not preclude this type of finding. The State's objection is consequently not of central relevance to the outcome of the rulemaking. Consequently, the EPA is denying these aspects of the petition.

Finally, Wisconsin argues that the final rule set a standard of performance for natural gas-fired stationary combustion turbines operating as base load units that cannot be achieved by simple cycle technology. Wisconsin makes no effort to explain how its objection meets the criteria for reconsideration under section 307(d)(7)(B).

At proposal, the EPA provided clear and adequate notice that the BSER for base load turbines was natural gas combined cycle (NGCC) technology. The EPA specifically rejected simple cycle technology as the BSER for this subcategory, noting that even advanced simple cycle units "have a base load rating of 1,150 lb CO₂/MWh, which is higher than the base load rating emission rates of 830 and 760 lb CO₂/MWh for the conventional and advanced NGCC model facilities, respectively." 79 FR 1430, 1485. The EPA also explained that "NGCC has a lower cost of electricity than simple cycle turbines at intermediate and high capacity factors" (i.e., base load operation). 79 FR 1485. The EPA received numerous comments on this issue. See Response to Comments Chapter 7.4.2 at 7-36 to 7-40 (EPA-HQ-OAR-2013-0495-1186); see also 80 FR 64,614/1 (summarizing comments).

In the final rule, the EPA explained:

Many commenters mistakenly thought that the EPA proposed to require some simple cycle combustion turbines to meet an emission standard of 1,000 lb CO₂/MWh-g, a level that they assert is unachievable. On the contrary, the EPA is not finding that NGCC technology and a corresponding emission standard of 1,000 lb CO₂/MWh-g is the BSER for simple cycle turbines. Instead, the EPA is finding that NGCC technology is the BSER for base load turbine applications. This means that if an owner or operator wants to sell more electricity to the grid than the amount derived from a unit's nameplate design efficiency calculated as a percentage of potential electric output, then the owner or operator should install a NGCC unit. If

⁸¹ Indeed, Congress amended section 111(a) in 1990 to remove the language that standards of performance reflect the best technological system and achieve a percent reduction in emissions, 80 FR 64537 n. 124, confirming that non-technological controls such as fuel substitution could be part of that best system. Similarly, under the CAA section 112 National Emission Standard for Hazardous Air Pollutant program, the EPA is mandated to consider "substitution of materials" in assessing what standards reflect performance of maximum achievable control technology. See CAA section 112(d)(2)(A).

the owner or operator elects to install a simple cycle turbine instead, then the practical effect of our final standards will be to limit the electric sales of that unit so that it serves primarily peak demand, not to subject it to an unachievable emission standard.

80 FR 64,615/2.

Because the grounds for Wisconsin's objection did not arise after the public comment period and Wisconsin has not explained how its concerns are centrally relevant, the EPA is denying reconsideration on this issue.

E. Response to EELI Petition

EELI's Petition is premised entirely on undocketed email communications between a single former EPA official and various members of non-governmental organizations (NGOs). Several dozen emails are attached as exhibits to the petition in support. EELI claims that these emails show that the whole rulemaking process was tainted by "*ex parte* communications", that the agency decision maker was impermissibly biased, and that the contacts between the single EPA official and NGO personnel constituted an advisory committee established in contravention of the provisions of the Federal Advisory Committee Act (FACA). The petition asserts lack of opportunity to raise its objection during the rulemaking because some of the emails in question were not yet available. According to the petition, the objection raised is of central relevance to the rulemaking's outcome because the rule's outcome was determined by non-agency personnel. EELI Petition p. 4 ("[t]his direction from private parties was not simply manifest in the final rule; it documents a predetermination of the material substance of the rule, controlled by non-agency personnel").

This petition is significantly incorrect as a matter of both law and fact. First, the concept of *ex parte* communication does not apply to informal rulemakings,⁸² either under the Administrative Procedure Act or under the procedural requirements of the Clean Air Act. *Sierra Club v. Costle*, 657 F. 2d 298, 400-402 (D.C. Cir. 1981).⁸³ The reason is that, unlike adjudicative proceedings, informal rulemakings involve policymaking, quasi-legislative types of determinations benefitting enormously from "continuing contact with a regulated industry, other affected groups, and the public". *Id.* at 401. Informal rulemakings stand in contrast with adjudicative, trial-type proceedings where conflicting claims to a valuable privilege militate in

⁸² "Informal rulemakings" (as opposed to rulemakings required by statute to be made on the record after opportunity for an agency hearing) involve notice by the agency via the Federal Register, and opportunity for public comment to that notice. 5 USC section 553(b) and (c).

⁸³ See also Administrative Conference of the United States "*Ex parte* communications in informal rulemakings" (June 10, 2014) stating "Informal communications between agency personnel and individual members of the public have traditionally been an important and valuable aspect of informal rulemaking proceedings conducted under section 4 of the Administrative Procedure Act (APA), 5 U.S.C. § 553. Borrowing terminology from the judicial context, these communications are often referred to as "*ex parte*" contacts.^[1] Although the APA prohibits *ex parte* contacts in formal adjudications and formal rulemakings conducted under the trial-like procedures of 5 U.S.C. §§ 556 and 557,^[2] 5 U.S.C. § 553 imposes no comparable restriction in the context of informal rulemaking". Available at <https://www.acus.gov/recommendation/ex-parte-communications-informal-rulemaking>

favor of insulation of the decision-maker. *Id.* at 400. EELI cites *Home Box Office v. FCC*, 567 F. 2d 9 (D.C. Cir. 1977) as its (sole) support. EELI Petition p.5. However, that case does not apply to informal rulemakings. *Sierra Club*, 657 F. 2d at 402 (“Later decisions of this court ... have declined to apply *Home Box Office* to informal rulemaking ... and there is no precedent for applying it to the procedures found in the Clean Air Act....”).

The EPA was also not required to docket these pre-proposal communications. Section 307(d)(3) of the Clean Air Act indicates that “[a]ll data, information, and documents referred to in this paragraph on which the proposed rule relies shall be included in the docket on the date of publication of the proposed rule.” However, when a proposed rule is not based on any information or data arising from a particular contact, the information is not required to be docketed. See *Sierra Club*, 657 F. 2d at 407. That is the case here. First, all of the emails attached as exhibits to the petition are from 2011 and relate to a different proposal than the one that led to the standard at issue here. In 2012, the EPA proposed a new source standard for coal-burning boilers, but withdrew that proposal and commenced a new proceeding. 77 FR 22392 (April 13, 2012); 79 FR 1352 (January 8, 2014) (withdrawing the 2012 proposal). The different proceeding at issue here was proposed at 79 FR 1430 (January 8, 2014). Second, the potential standards discussed in the emails are unrelated to those that the EPA proposed. Thus, the emails discuss a potential standard of 1,600-2,100 lb CO₂/MWh based on burning natural gas along with coal. The standards that the EPA proposed were 1,000 lb CO₂/MWh based in the withdrawn proposal on constructing only natural gas combined cycle plants (i.e., not burning coal at all) (77 FR 22392), or (in the new proposal) on the performance of a control technology, carbon capture and sequestration, which uses a chemical process to capture CO₂ and convert it to a phase state where it can be piped to a sequestration site for permanent disposition. 79 FR 1446, 1469-75. There is no requirement to docket information on regulatory alternatives that the agency never proposed, never solicited comment on, and never otherwise pursued.

Moreover, the EPA did disclose all factual and methodological information underlying the proposal, indeed exhaustively so. See, e.g., 79 FR 1462-1485 (legal rationale for proposal; rationale for proposed selection of partial CCS as BSER; cost information; information on geologic sequestration of captured CO₂). Even were the suggestions of outside parties reflected in a proposal (which is not the case here), then what would matter would be the content of that proposal, and whether the data and methodology underlying the proposal are disclosed. This is the information that is critical to a proposed rule (see CAA section 307(d)(3)(A)-(C)), not the identity of individuals making suggestions.⁸⁴

⁸⁴ As it happens, EPA staff sought out the views of numerous parties from industry and academia, as well as the environmental community, in crafting the new source performance standards. See e.g., Meeting with Lignite Energy Council on 05/09/14 <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-9674>; EPA Meeting with Golden Spread Electric Cooperative on June 17, 2014 <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-11064>; Meeting between EPA and Representative Tom Sloan on January 6, 2014 <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0078>;

The further suggestion that the EPA's decision is the product of impermissible bias is untenable. See generally RTC Response 2.4-19. Petitioners need to make a "clear and convincing showing of an unalterably closed mind on a matter critical to disposition of the proceeding". *Lead Industries Ass'n v. EPA*, 647 F. 2d 1130, 1178 (D.C. Cir. 1980). At most, the Petition shows that one EPA official, who was not in the lead office developing the rulemaking, sought out pre-proposal comment on regulatory alternatives that the agency never pursued, which alternatives were considerably less stringent than the standards the EPA actually proposed. Rhetorical flourishes notwithstanding, the Petitioner has failed to make any semblance of the requisite showing here.

For all of these reasons, the EPA is denying this Petition.

V. Conclusion

The new source standards require a new coal-burning power plant to reduce carbon dioxide emissions to a level reflecting both the most highly efficient boiler design, and partial capture and sequestration of carbon dioxide. Carbon capture and sequestration is a proven technology, with a history of reliable use at coal-fired plants and other industrial sources. At the level of capture on which the standard of performance is predicated, partial capture and sequestration is available at reasonable cost. An unprecedented coalition of major industrial entities (including Peabody Energy, Arch Coal, Archer Daniel Midland, Occidental Petroleum), major NGOs, unions (including the AFL-CIO), and diverse states (including Kentucky, Maryland, and Michigan) recently stated that "CCUS [carbon capture utilization and storage] represents an essential component of our nation's strategy for achieving greenhouse gas emission reductions. Without widespread deployment of CCUS technologies, we will simply fail to meet global mid-century goals for mitigating carbon emissions from electric power generation and a wide range of industrial activity."⁸⁵ The same impressive coalition noted that "[c]apturing and

USEPA Meeting with EEI Regarding CAA 111(b) and (d) Proposals for GHG Emissions from EGUs, February 3, 2015 <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-11270>;
Meeting with NRDC Regarding Proposed Carbon Pollution Standard for New Power Plants, December 18, 2014 <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-11269>;
AES Meeting on 05-13-14 <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-10947>;

Meeting between USEPA and Union representatives on July 26, 2013
<http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0061>;

Attendee List from USEPA Meeting with GE on December 16, 2013
<http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0071>;

Meeting with Environment America on 05-09-14 <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-9673>;

Meeting Memorandum <http://www.regulations.gov/#!documentDetail;D=EPAHQ-OAR-2013-0495-11806>;

Meeting between USEPA and Power4Georgians on February 13, 2013
<http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0063>.

⁸⁵ Letter of February 3, 2016 from coalition members to the Honorable Kevin Brady and the Honorable Sander Levin, urging retention of the section 45Q tax credit for carbon capture and utilization; see also

utilizing power plant and industrial CO₂ through EOR [enhanced oil recovery] yields additional American oil from existing wells that would otherwise not be accessed thereby expanding domestic reserves and reducing imports. The United States independent oil and gas industry is the world leader in CO₂-EOR and could produce billions of barrels of additional American oil from existing fields, while safely and permanently storing billions of tons of CO₂.⁸⁶

The standards of performance also serve to promote further development and implementation of carbon capture and sequestration technology. It is a documented phenomenon that national rules requiring large emission reductions have resulted in significant upswing in inventive activity to develop and perfect needed emission control technologies. 80 FR 64575.

The new source performance standard will not be an impediment to construction of new coal-burning capacity. Indeed, availability and deployment of carbon capture technology could prove a lifeline to the industry. As the scourge of climate change becomes increasingly manifest, the ability to use coal without substantially adding to CO₂ emissions will be more and more important. The new source performance standard sends a strong signal that low-emitting coal-burning capacity is feasible, and that coal can thereby have an important place in a lower-carbon energy future. As American Electric Power stated, “AEP still believes the advancement of CCS is critical for the sustainability of coal-fired generation.” 80 FR 64572.⁸⁷ The petitions for reconsideration here present no information that cause the EPA to deviate from these findings and conclusions.

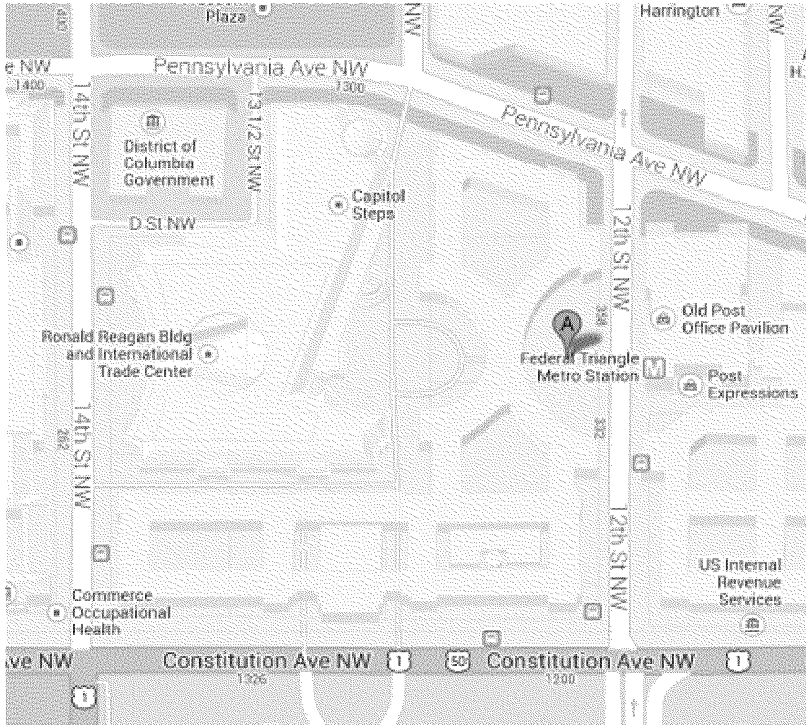
The petitions for review of UARG, Ameren, AEP, State of Wisconsin, and Energy and Environment Legal Institute are denied in their entirety.

parallel letter from the same coalition to Senators Orrin Hatch and Ron Wyden (April 4, 2016). These letters are part of the record for this action.

⁸⁶ Id.

⁸⁷ The quote is from “CCS LESSONS LEARNED REPORT American Electric Power Mountaineer CCS II Project Phase I”, prepared for the Global CCS Institute project #PRO 004, January 23, 2012, p. 2. (EPA-HQ-OAR-2013-0495-11680).

From: Browne, Cynthia
Location: DCRoomARN5415PolyPCTB/DC-ARN-OAR | 1200 Pennsylvania Avenue, NW, William Jefferson Clinton Federal Building, Washington, DC 20460
Importance: Normal
Subject: Meeting Re: UARG Response to EPA 111(d) Questions | WJCN 5415 | Conference: 1-
Conf Code Participant Code: **Conf Code**
Categories: Blue Category
Start Date/Time: Thur 12/12/2013 7:00:00 PM
End Date/Time: Thur 12/12/2013 8:00:00 PM
FW: UARG Response to EPA 111(d) Questions; request for dialogue

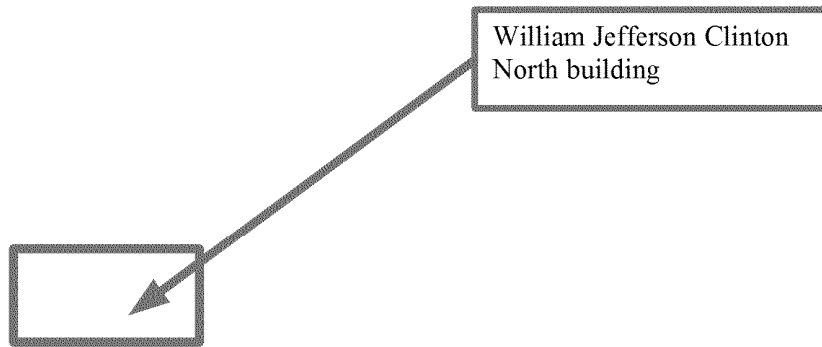


Directions and procedures: If you come by Metro the Federal Triangle metro stop is directly below the building entrances. You would leave the metro station and go up all three sets of escalators and turn right. You will see a set of stairs and glass Doors with EPA Signified on Glass. That is William Jefferson Clinton North (formerly Ariel Rios)

If you are coming by taxi, you would want to be dropped off on 12th NW, between Constitution Ave and Pennsylvania Ave. It is almost exactly half way between the two avenues on 12th. From 12th Street, facing the building with the EPA and American flags, walk toward the building and take the glass door on your right hand side with the escalators going down to the metro on your left. This again will be the North Lobby of the William Jefferson Clinton North.

Upon entering the lobby, the meeting attendees will be asked to pass through security and provide a photo ID for entrance. Let the guards know that you were instructed to call 202-564-7400. If you are travelling in a large group, you may want to arrive 10-15 minutes early in order to be on time for the meeting.

Map:



To: Goffman, Joseph[Goffman.Joseph@epa.gov]
Cc: Drinkard, Andrea[Drinkard.Andrea@epa.gov]; Browne, Cynthia[Browne.Cynthia@epa.gov]
From: Wood, Allison D.
Sent: Fri 5/22/2015 11:13:54 PM
Subject: RE: Utility Air Regulatory Group meeting

Joe, you're not testing my patience at all! This is great! I will work with Cynthia to get a time. We would like to have you on either the afternoon of June 18 (anytime from 1:00 p.m. on) or on the morning of June 19 (anytime from 8:30 a.m. through noon). Thank you so much for getting back to me!

Allison

From: Goffman, Joseph [Goffman.Joseph@epa.gov]
 Sent: Friday, May 22, 2015 7:04 PM
 To: Wood, Allison D.
 Cc: Drinkard, Andrea; Browne, Cynthia
 Subject: RE: Utility Air Regulatory Group meeting

Hello, again, Allison. Sorry to be testing your patience yet again, but having decided to stay in town the week of June 15, I should now have some availability to participate in the meeting if it turns out that your invitation still stands – or can be re-opened. Cynthia Brown can work with you on pinning down a time if you want to proceed. Many thanks.

Joe Goffman

Joseph Goffman
 Associate Assistant Administrator for Climate
 and Senior Counsel
 Office of Air and Radiation
 US EPA
 Washington, DC.

From: Goffman, Joseph
 Sent: Monday, May 18, 2015 12:08 AM
 To: Wood, Allison D.
 Cc: Drinkard, Andrea
 Subject: Re: Utility Air Regulatory Group meeting

Hi, Allison. Thank you for the invitation and thank you for your patience in waiting for a response. As it turns out, that week is already shaping up to be a tough one to make any additional commitments for, so I am hoping that I can get a rain check. Thanks.

- Joseph Goffman
 Sent from my iPhone

On May 12, 2015, at 4:06 PM, Wood, Allison D. <awood@hunton.com<<mailto:awood@hunton.com>>>>
 wrote:
 Dear Joe,

I just left a message on your voicemail and thought I would follow up with an email in case that is more

convenient for you. As I explained in my voicemail, the Utility Air Regulatory Group (UARG) is having a large meeting on June 18-19 in our offices in Washington. In the past, EPA representatives have been willing to come and speak with UARG members about issues of importance to them. Naturally, the thing they are most interested in right now is the Clean Power Plan, and I was hoping you might be able to come and speak on that to them.

Could you please let me know if you are willing and available to do that? Thanks for considering this request.

Best regards,

Allison

Allison D. Wood
Partner
awood@hunton.com<mailto:awood@hunton.com>
p

202.955.1945

bio<<http://webdownload.hunton.com/esignature/bio.aspx?U=01383>> |
vCard<<http://webdownload.hunton.com/esignature/vcard.aspx?U=01383>>

Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037
hunton.com<<http://www.hunton.com>>

To: Goffman, Joseph[Goffman.Joseph@epa.gov]
Cc: Drinkard, Andrea[Drinkard.Andrea@epa.gov]; Browne, Cynthia[Browne.Cynthia@epa.gov]
From: Wood, Allison D.
Sent: Fri 5/22/2015 11:13:54 PM
Subject: RE: Utility Air Regulatory Group meeting

Joe, you're not testing my patience at all! This is great! I will work with Cynthia to get a time. We would like to have you on either the afternoon of June 18 (anytime from 1:00 p.m. on) or on the morning of June 19 (anytime from 8:30 a.m. through noon). Thank you so much for getting back to me!

Allison

From: Goffman, Joseph [Goffman.Joseph@epa.gov]
Sent: Friday, May 22, 2015 7:04 PM
To: Wood, Allison D.
Cc: Drinkard, Andrea; Browne, Cynthia
Subject: RE: Utility Air Regulatory Group meeting

Hello, again, Allison. Sorry to be testing your patience yet again, but having decided to stay in town the week of June 15, I should now have some availability to participate in the meeting if it turns out that your invitation still stands – or can be re-opened. Cynthia Brown can work with you on pinning down a time if you want to proceed. Many thanks.

Joe Goffman

Joseph Goffman
Associate Assistant Administrator for Climate
and Senior Counsel
Office of Air and Radiation
US EPA
Washington, DC.

From: Goffman, Joseph
Sent: Monday, May 18, 2015 12:08 AM
To: Wood, Allison D.
Cc: Drinkard, Andrea
Subject: Re: Utility Air Regulatory Group meeting

Hi, Allison. Thank you for the invitation and thank you for your patience in waiting for a response. As it turns out, that week is already shaping up to be a tough one to make any additional commitments for, so I am hoping that I can get a rain check. Thanks.

- Joseph Goffman
Sent from my iPhone

On May 12, 2015, at 4:06 PM, Wood, Allison D. <awood@hunton.com<mailto:awood@hunton.com>> wrote:
Dear Joe,

I just left a message on your voicemail and thought I would follow up with an email in case that is more convenient for you. As I explained in my voicemail, the Utility Air Regulatory Group (UARG) is having a large meeting on June 18-19 in our offices in Washington. In the past, EPA representatives have been

willing to come and speak with UARG members about issues of importance to them. Naturally, the thing they are most interested in right now is the Clean Power Plan, and I was hoping you might be able to come and speak on that to them.

Could you please let me know if you are willing and available to do that? Thanks for considering this request.

Best regards,

Allison

Allison D. Wood
Partner
awood@hunton.com<mailto:awood@hunton.com>
p

202.955.1945

bio<<http://webdownload.hunton.com/esignature/bio.aspx?U=01383>> |
vCard<<http://webdownload.hunton.com/esignature/vcard.aspx?U=01383>>

Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037
hunton.com<<http://www.hunton.com>>

To: Goffman, Joseph[Goffman.Joseph@epa.gov]
From: Wolff, Brian
Sent: Sun 5/10/2015 8:15:09 PM
Subject: Re: CEO 111(d) Working Group Call: Wednesday, May 13, 4pm EDT

Got it thanks. Good feedback

Sent from my iPhone

On May 10, 2015, at 3:41 PM, Goffman, Joseph <Goffman.Joseph@epa.gov> wrote:

Thanks, Brian. As folks discuss what they are calling the technical potential approach to building block 3, it is essential that they remember that we intended that approach to encompass economic considerations, not just technical considerations. Perhaps even more important is that in order to make a determination that a particular technology or level of use of that technology represents the best system of emissions reduction, the determination has to meet critical criteria of cost and feasibility, and in applying the technology to generate a standard of performance we again have to establish cost reasonableness and feasibility. It appears as if folks are interpreting what they are calling the technical potential approach as one that is somehow not subject to any of those constraints.

- Joseph Goffman
 Sent from my iPhone

On May 10, 2015, at 2:25 PM, Wolff, Brian <BWolff@eei.org> wrote:

Sent from my iPhone

Begin forwarded message:

From: "Kuhn, Thomas" <TKuhn@eei.org>
Date: May 10, 2015 at 2:22:56 PM EDT
To: "ted.craver@edisonintl.com" <ted.craver@edisonintl.com>, Nick Akins <nkakins@aep.com>, "tafannin@southernco.com" <tafannin@southernco.com>, "christopher.crane@exeloncorp.com" <christopher.crane@exeloncorp.com>, "Abel, Gregory E (U.S.)" <GEAbel@berkshirehathawayenergyco.com>, "wjfehrman@midamerican.com" <wjfehrman@midamerican.com>, "msf@nei.org" <msf@nei.org>, "jonesc@firstenergycorp.com" <jonesc@firstenergycorp.com>, Gerard M Anderson <andersong@dteenergy.com>, "Baxter, Warner L" <WBaxter@ameren.com>, "terry.bassham@kcpl.com" <terry.bassham@kcpl.com>, "DENAULT, LEO P" <LDENAUL@entergy.com>, "Earley, Anthony" <[ED_001013_00007108-00001](mailto:anthony.earley@pge-</p>
</div>
<div data-bbox=)

corp.com>, "pfarr@pplweb.com" <pfarr@pplweb.com>, "thomas.farrell@dom.com" <thomas.farrell@dom.com>, "Fowke, Ben" <ben.fowke@xcelenergy.com>, "lynn.good@duke-energy.com" <lynn.good@duke-energy.com>, "ralph.izzo@pseg.com" <ralph.izzo@pseg.com>, "jonesc@firstenergycorp.com" <jonesc@firstenergycorp.com>, "Robo, Jim" <Jim.Robo@nexteraenergy.com>, "dean.seavers@nationalgrid.com" <dean.seavers@nationalgrid.com>, "whspence@pplweb.com" <whspence@pplweb.com>, "Young, John" <John.Young@energyfutureholdings.com>, "Pat.Collawn@pnmresources.com" <Pat.Collawn@pnmresources.com>, "boyds@dteenergy.com" <boyds@dteenergy.com>, "jmcmanus@aep.com" <jmcmanus@aep.com>, "CSWoollums@berkshirehathawayenergyco.com" <CSWoollums@berkshirehathawayenergyco.com>, "jennifer.weber@duke-energy.com" <jennifer.weber@duke-energy.com>
Cc: "Katherine.Wong@edisonintl.com" <Katherine.Wong@edisonintl.com>, Lorraine R Harris <lrharris@aep.com>, "chadgraf@southernco.com" <chadgraf@southernco.com>, "Austin, Linda A:(BSC)" <linda.austin@exeloncorp.com>, "Nixon, Tami L" <TLNixon@berkshirehathawayenergyco.com>, "dsjohnston@midamerican.com" <dsjohnston@midamerican.com>, "REYNOLDS, Deirdre" <dmr@nei.org>, "Durinsky, Cindy J." <durinskyc@firstenergycorp.com>, "koschn@dteenergy.com" <koschn@dteenergy.com>, "Held, Paula J" <PHeld@ameren.com>, West Betsey <Betsey.West@kcpl.com>, "ASSAD, ANN M" <aassad@entergy.com>, "Youngblood, Soo Ling" <SooLing.Youngblood@pge-corp.com>, "Brenda Long (Services - 6)" <brenda.long@dom.com>, "McIsaac, Tammy" <tammy.l.mcisaac@xcelenergy.com>, "Sims, Bobbie A" <Bobbie.Sims@duke-energy.com>, "Livezey, Amy E" <Amy.Livezey@duke-energy.com>, "DiIorio, Rosann" <Rosann.DiIorio@pseg.com>, "Tervo, Judith A." <Judith.Tervo@nationalgrid.com>, "diane.warner@nexteraenergy.com" <diane.warner@nexteraenergy.com>, "Pickens, Margaret" <MPickens@energyfutureholdings.com>, "Edwards, Cindy" <Cindy.Edwards@pnmresources.com>, "'Castillo, Mildred A'" <macastillo@pplweb.com>, "aemanning@pplweb.com" <aemanning@pplweb.com>, "Tyler, Tina P" <Tina.Tyler@duke-energy.com> (Tina.Tyler@duke-energy.com)" <Tina.Tyler@duke-energy.com>
Subject: CEO 111(d) Working Group Call: Wednesday, May 13, 4pm EDT

Please note that Ted Craver and I will hold a call for interested work group members next Wednesday, May 13. at 4 p.m. EDT. The purpose of the call will be to de-brief on our recent meeting with EPA Administrator McCarthy and her two key deputies, and discuss our next steps. Thanks again to those of you

that were able to participate.

In summary, our meeting went well overall. The Administrator clearly understands our concerns with the timing and stringency of the near term targets and their potential impact on reliability, and continues to be willing to work with us to find an alternative approach. She also understands our concerns with the use of the technical potential approach to renewable energy generation under Building Block 3. Nonetheless, we still have work to do on both of these important topics.

To participate in the call, please ask your Assistant to RSVP to Lisa Hayes (lhayes@eei.org), who will provide the call-in information.

Thank you for the continued efforts by you and your respective teams on this critical issue. I hope that you will be able to join us on May 13. In the interim, please do not hesitate to contact me if you have any questions, or have your staff contact Quin Shea (qshea@eei.org or 202-508-5027).

<111d-CEOWorkGrpCallNote050815.doc>

To: Goffman, Joseph[Goffman.Joseph@epa.gov]
From: Wolff, Brian
Sent: Sun 5/10/2015 6:25:01 PM
Subject: Fwd: CEO 111(d) Working Group Call: Wednesday, May 13, 4pm EDT
 111d-CEOWorkGrpCallNote050815.doc
[ATT00001.htm](#)

Sent from my iPhone

Begin forwarded message:

From: "Kuhn, Thomas" <TKuhn@eei.org>
Date: May 10, 2015 at 2:22:56 PM EDT
To: "ted.craver@edisonintl.com" <ted.craver@edisonintl.com>, Nick Akins
 <nkakins@aep.com>, "tafannin@southernco.com" <tafannin@southernco.com>,
 "christopher.crane@exeloncorp.com" <christopher.crane@exeloncorp.com>, "Abel,
 Gregory E (U.S.)" <GEAbel@berkshirehathawayenergyco.com>,
 "wjfehrman@midamerican.com" <wjfehrman@midamerican.com>, "msf@nei.org"
 <msf@nei.org>, "jonesc@firstenergycorp.com" <jonesc@firstenergycorp.com>, Gerard M
 Anderson <andersong@dteenergy.com>, "Baxter, Warner L" <WBaxter@ameren.com>,
 "terry.bassham@kcpl.com" <terry.bassham@kcpl.com>, "DENAULT, LEO P"
 <LDENAUL@entergy.com>, "Earley, Anthony" <anthony.earley@pge-corp.com>,
 "pfarr@pplweb.com" <pfarr@pplweb.com>, "thomas.farrell@dom.com"
 <thomas.farrell@dom.com>, "Fowke, Ben" <ben.fowke@xcelenergy.com>,
 "lynn.good@duke-energy.com" <lynn.good@duke-energy.com>, "ralph.izzo@pseg.com"
 <ralph.izzo@pseg.com>, "jonesc@firstenergycorp.com" <jonesc@firstenergycorp.com>,
 "Robo, Jim" <Jim.Robo@nexteraenergy.com>, "dean.seavers@nationalgrid.com"
 <dean.seavers@nationalgrid.com>, "whspence@pplweb.com" <whspence@pplweb.com>,
 "Young, John" <John.Young@energyfutureholdings.com>,
 "Pat.Collawn@pnmresources.com" <Pat.Collawn@pnmresources.com>,
 "boyds@dteenergy.com" <boyds@dteenergy.com>, "jmcmanus@aep.com"
 <jmcmanus@aep.com>, "CSWoollums@berkshirehathawayenergyco.com"
 <CSWoollums@berkshirehathawayenergyco.com>, "jennifer.weber@duke-energy.com"
 <jennifer.weber@duke-energy.com>
Cc: "Katherine.Wong@edisonintl.com" <Katherine.Wong@edisonintl.com>, Lorraine R
 Harris <lrharris@aep.com>, "chadgraf@southernco.com" <chadgraf@southernco.com>,
 "Austin, Linda A:(BSC)" <linda.austin@exeloncorp.com>, "Nixson, Tami L"
 <TLNixson@berkshirehathawayenergyco.com>, "dsjohnston@midamerican.com"
 <dsjohnston@midamerican.com>, "REYNOLDS, Deirdre" <dmr@nei.org>, "Durinsky,
 Cindy J." <durinskyc@firstenergycorp.com>, "koschn@dteenergy.com"
 <koschn@dteenergy.com>, "Held, Paula J" <PHeld@ameren.com>, West Betsey
 <Betsey.West@kcpl.com>, "ASSAD, ANN M" <aassad@entergy.com>, "Youngblood, Soo
 Ling" <SooLing.Youngblood@pge-corp.com>, "Brenda Long (Services - 6"
 <brenda.long@dom.com>, "McIsaac, Tammy" <tammy.l.mcisaac@xcelenergy.com>,
 "Sims, Bobbie A" <Bobbie.Sims@duke-energy.com>, "Livezey, Amy E"

<Amy.Livezey@duke-energy.com>, "DiIorio, Rosann" <Rosann.DiIorio@pseg.com>, "Tervo, Judith A." <Judith.Tervo@nationalgrid.com>, "diane.warner@nexteraenergy.com" <diane.warner@nexteraenergy.com>, "Pickens, Margaret" <MPickens@energyfutureholdings.com>, "Edwards, Cindy" <Cindy.Edwards@pnmresources.com>, "Castillo, Mildred A" <macastillo@pplweb.com>, "aemanning@pplweb.com" <aemanning@pplweb.com>, "Tyler, Tina P" <Tina.Tyler@duke-energy.com> (Tina.Tyler@duke-energy.com)" <Tina.Tyler@duke-energy.com>
Subject: CEO 111(d) Working Group Call: Wednesday, May 13, 4pm EDT

Please note that Ted Craver and I will hold a call for interested work group members next Wednesday, May 13, at 4 p.m. EDT. The purpose of the call will be to de-brief on our recent meeting with EPA Administrator McCarthy and her two key deputies, and discuss our next steps. Thanks again to those of you that were able to participate.

In summary, our meeting went well overall. The Administrator clearly understands our concerns with the timing and stringency of the near term targets and their potential impact on reliability, and continues to be willing to work with us to find an alternative approach. She also understands our concerns with the use of the technical potential approach to renewable energy generation under Building Block 3. Nonetheless, we still have work to do on both of these important topics.

To participate in the call, please ask your Assistant to RSVP to Lisa Hayes (lhaves@eei.org), who will provide the call-in information.

Thank you for the continued efforts by you and your respective teams on this critical issue. I hope that you will be able to join us on May 13. In the interim, please do not hesitate to contact me if you have any questions, or have your staff contact Quin Shea (qshea@eei.org or 202-508-5027).

May 8, 2015

To: EEI CEO 111(d) Work Group

Please note that Chairman Craver and I will hold a call for interested work group members next [Wednesday, May 13 at XX:00 p.m. EDT.] The purpose of the call will be to de-brief on our recent meeting with EPA Administrator McCarthy and her two key deputies, and to discuss our next steps. Thanks again to those of you that were able to participate.

In summary, our meeting went well overall. The Administrator clearly understands our concerns with the timing and stringency of the near term targets and their potential impact on reliability, and continues to be willing to work with us to find alternative approaches. She also understands our concerns with the use of the technical potential approach to renewable energy generation under Building Block 3. Nonetheless, we still have work to do on both of these important topics.

To participate in the call, please ask your Assistant to RSVP to Lisa Hayes (lhayes@eei.org), who will provide the call-in information.

Thank you for the continued efforts by you and your respective teams on this critical issue. I hope that you will be able to join us on May 13. In the interim, do not hesitate to contact me if you have any questions, or have your staff contact Quin Shea (qshea@eei.org or 202-508-5027).

To: Goffman, Joseph[Goffman.Joseph@epa.gov]
From: Wolff, Brian
Sent: Wed 2/25/2015 6:27:13 PM
Subject: "Affirmative Declarations" Paper
[111d-GlidePathCriteriaMemberSuggestionsRev.docx](#)

Joe –

We missed you at dinner on Monday night – hope Colorado was productive.

Per our January 30 discussion with you and Janet, EEI staff canvassed comments submitted by our member companies and developed the attached compendium. As discussed, we focused on language that correlates to EPA's expressed interest in ensuring that state and regional plans contain incremental and verifiable reductions throughout the compliance period (e.g., specific criteria addressing accountability). Many of the company comments are consistent with EEI material flagged by EPA at our meeting .

Brian L. Wolff

Executive Vice President,

Policy & External Affairs

Edison Electric Institute

701 Pennsylvania Avenue NW

Washington, DC 20004

Email: bwolff@eei.org | Direct: 202.508.5300 | Fax: 202.508.5783



Edison Electric Institute

Power by Association™

To: Goffman, Joseph[Goffman.Joseph@epa.gov]
From: Wolff, Brian
Sent: Mon 12/1/2014 4:58:01 PM
Subject: Fwd: Docket No. EPA-HQ-OAR-2013-0602; Comments of the Edison Electric Institute
[EEI 111\(d\) Comments Final 12012014.pdf](#)
[ATT00001.htm](#)
[image001.gif](#)
[ATT00002.htm](#)

See attached

Also can you look at Gina sched for Executive committee fly in
Jan 21 jan 23
Jan 26 jan 27 or 28
30.

Thanks b

Sent from my iPhone

Begin forwarded message:

From: "Bond, Alex" <Abond@eei.org>
To: "mccarthy.gina@epa.gov" <mccarthy.gina@epa.gov>
Cc: "Kuhn, Thomas" <TKuhn@eei.org>, "Wolff, Brian" <BWolff@eei.org>, "Owens, David" <DOwens@eei.org>, "Shea, Quin" <QShea@eei.org>, "Fisher, Emily" <EFisher@eei.org>
Subject: Docket No. EPA-HQ-OAR-2013-0602; Comments of the Edison Electric Institute

Administrator McCarthy,

Please find the comments of the Edison Electric Institute (EEI) on the proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units issued by the Environmental Protection Agency in Docket No. EPA-HQ-OAR-2013-0602. 79 Fed. Reg. 34,830 (June 18, 2014) attached to this email. These comments also address the subsequently issued Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Notice of Data Availability, 79 Fed. Reg. 64,534 (Oct. 30, 2014). EEI looks forward to continuing our dialog with the Agency on this complex and significant rulemaking.

Thank you!

Alex

--

Alex Bond
Manager, Air Quality & Climate Programs
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
202-508-5710
www.eei.org<<http://www.eei.org>>

Follow EEI on Twitter<http://www.twitter.com/Edison_Electric>,
Facebook<<http://www.facebook.com/pages/Edison-Electric-Institute/253118344285>>, and
YouTube<<http://www.youtube.com/eeitv>>.

[cid:image001.gif@01D00D4F.0AB02D80]

To: Goffman, Joseph[Goffman.Joseph@epa.gov]
From: Wolff, Brian
Sent: Sat 5/31/2014 2:35:02 PM
Subject: Re: RE:

Great. Can you shoot me his email. Thx joe

Sent from my iPhone

On May 31, 2014, at 10:33 AM, "Goffman, Joseph" <Goffman.Joseph@epa.gov> wrote:

Just to talked to her a got a positive response. Please get an invite into Matthew Fritz.
Thanks.

From: Wolff, Brian [<mailto:BWolff@cci.org>]
Sent: Saturday, May 31, 2014 9:52 AM
To: Goffman, Joseph
Subject: Re:

This is time in Vegas

7:00 am Monday morning 6/9.

Sent from my iPhone

On May 31, 2014, at 9:02 AM, "Goffman, Joseph" <Goffman.Joseph@epa.gov> wrote:

Thanks, Brian. On it.

Sent from my BlackBerry 10 smartphone.

From: Wolff, Brian
Sent: Saturday, May 31, 2014 8:58 AM
To: Goffman, Joseph
Subject: Fwd:

Please do not share with anyone other than Gina. I believe now more than yesterday that we need her in Vegas to reset the table. She is great with them. The WH is very bad at outreach and proper messaging.

Please do not share below other than with her.

Thanks Joe

Brian

Sent from my iPhone

Begin forwarded message:

From: "Kuhn, Thomas" <TKuhn@eei.org>
Date: May 31, 2014 at 6:30:31 AM EDT
To: "Earley, Anthony" <anthony.earley@pge-corp.com>
Cc: "Yackira, Michael" <MYackira@nvenergy.com>, "ted.craver@edisonintl.com" <ted.craver@edisonintl.com>, Nick Akins <nkakins@aep.com>, "Fanning, Thomas A." <TAFANNIN@southernco.com>, "thomas.farrell@dom.com" <thomas.farrell@dom.com>, "Crane, Christopher M:(BSC)" <christopher.crane@exeloncorp.com>
Subject: RE: EEI Leadership Call with John Podesta on 111(d) - SATURDAY, May 31, 1:00 pm EDT; PRE-CALL at 12:30 pm EDT

Tony: I tremendously appreciate your comments, and fully agree that the Administration is off to a horrible start in terms of how they are dealing with us on this proposed rule.

As you know, we were not invited to participate in the call you mentioned. I heard it characterized in the same way. Rather than continuing to work with us as a whole, I believe they are trying to go back to the old "divide and conquer" strategy. I commend you for the comments you made on the call strongly emphasizing that this is not the way to do business with us. This is an incredibly important and far-reaching rule which is focused on our industry, and I believe they need to deal with the industry as a whole. Brian Wolff conveyed this message to Podesta, which is the reason they are now saying that they want to talk with our Leadership. Having said that, I agree with you that we don't need a call without any substance that is only trying to check the box in their efforts to generate political support.

While I am very unhappy with the process, my primary concern, which we all share, is the substance. While we have heard over the past year bits and pieces about the direction in which they are heading, there will be much to digest when the proposed rule is issued. However, I am very concerned about yesterday's press reports suggesting that they intend to change the baseline from 2005 to 2013. While the numbers aren't out yet for 2013, we have achieved a substantial reduction in carbon emissions (somewhere in the neighborhood of 12 - 14%) during that timeframe. Politically, you would think that they would want to take credit for that achievement, and it certainly is a good talking point for our industry. If they change the baseline to 2013, they will take away all that we have achieved, and we all know that we did that through a very weak economy, lower gas prices and the mercury/MACT rule. Press reports suggest a targeted goal of 6% by 2020, which would exceed the Waxman/Markey numbers and the President's former target of 17% from 2005 levels by the year 2020. When you add up the numbers, it is not a huge increase by 2020, but again, the reports suggest a much higher target for 2030. If they are looking at a 25% reduction from 2013 levels (as reported), it would be much higher than the Waxman/Markey target. As you know, since we deal with long-term assets, time frames are incredibly important to us, flexibility mechanisms notwithstanding. While I don't want to prematurely jump-the-gun, and you and the Leadership are responsible for final policy decisions, I felt it important to raise these issues. As you indicated, there will also be many other issues for us to consider, as we did collectively in the mercury rule.

I apologize for the last minute scheduling for today's call – they dictated the time. Your suggestion to change it to Sunday night might be a good one, although they will continue their campaign to build political support over the weekend. They were originally going to have the President roll this out on Monday, but I understand they have now backed away from that strategy. We will check in with them this morning and keep you posted.

Thank you again for being "Horatio at the Bridge" at the first encounter.

-----Original Message-----

From: Earley, Anthony [<mailto:anthony.earley@pge-corp.com>]
Sent: Saturday, May 31, 2014 12:40 AM
To: Kuhn, Thomas
Cc: Yackira, Michael; ted.craver@edisonintl.com; Nick Akins; Fanning, Thomas A.; Earley, Anthony; thomas.farrell@dom.com; Crane, Christopher M:(BSC)
Subject: Re: EEI Leadership Call with John Podesta on 111(d) – SATURDAY, May 31, 1:00 pm EDT; PRE-CALL at 12:30 pm EDT

Tom -

I cannot make the call tomorrow but I wanted to give you my reaction to this evening's call.

I can't remember a call that insulted our industry's intelligence more than that one. They did not say one thing that we didn't know already and gave us absolutely no useful info on what the rule would say. Rather than engage us as partners in trying to formulate an incredibly important policy discussion, they told us that we were the biggest carbon polluter and we should jump on their bandwagon. It was a blatantly political presentation rather than an effort to treat us as partners. I think the deafening silence when they asked for questions and comments spoke volumes.

As an industry, I think we have to be at the table, but we are not off to a good start. I think we should let them know we are disappointed in the call today and decline to ask our members to participate tomorrow. I would suggest a Sunday afternoon or evening call to send the message that we don't intend to be rolled on this one.

Tony

Sent from my iPad

On May 30, 2014, at 10:23 PM, "Igoe, Joanne" <JIgoe@eei.org<<mailto:JIgoe@eei.org>>> wrote:

We have been requested by John Podesta to convene a call Saturday afternoon at 1 pm (EDT) with him and other senior White House officials regarding EPA's pending release of the 111(d) GHG emission reduction guidelines proposal. We anticipate that this call will be very different than the series of general outreach calls White House staff currently are holding with various stakeholder groups and individual CEOs in our industry. We also expect to obtain specific details on key issues underlying the proposal.

I apologize for the late notification, but under the circumstances I think you will agree with me that it is worth our collective time and commitment. To prepare for the 1 pm call, we will hold a 12:30 pm pre-call. Specific call information is listed below.

12:30pm Pre-Call: DIAL: 1-877-418-3859; ask for the EEI Leadership Call;

1:00pm Podesta Call: DIAL: 1-800-860-2442; ask for the EEI/Kuhn Call.

I suspect you are current on the policy initiative in play via recent press reports and through conversations with your respective teams. Tomorrow's call is a fundamental step in what will be an intense, CEO-level dialog regarding how best to engage within the membership and with the Administration on this important issue. It is vital that our discussion with John Podesta include coverage of the most critical issues underlying the proposal, including the following:

- How EPA has defined the best system of emissions reduction (BSER) in setting the reduction guidelines
- Emission reduction guidelines for states
- Compliance timeframes (including recognition of emission reduction investments that have already been made)
- Baseline
- Compliance flexibility (including recognition of early action)

I hope that your schedule will permit you to participate in tomorrow's calls. In the interim, please contact me (202-508-5555) with any questions. Thank you for your continued leadership on this important issue.

PG&E is committed to protecting our customers' privacy.

To learn more, please visit

<http://www.pge.com/about/company/privacy/customer/>

To: Goffman, Joseph[Goffman.Joseph@epa.gov]
From: Wolff, Brian
Sent: Sat 5/31/2014 1:52:18 PM
Subject: Re:

This is time in Vegas
7:00 am Monday morning 6/9.

Sent from my iPhone

On May 31, 2014, at 9:02 AM, "Goffman, Joseph" <Goffman.Joseph@epa.gov> wrote:

Thanks, Brian. On it.

Sent from my BlackBerry 10 smartphone.

Please do not share with anyone other than Gina. I believe now more than yesterday that we need her in Vegas to reset the table. She is great with them. The WH is very bad at outreach and proper messaging.

Please do not share below other than with her.

Thanks Joe

Brian

Sent from my iPhone

Begin forwarded message:

From: "Kuhn, Thomas" <TKuhn@eei.org>
Date: May 31, 2014 at 6:30:31 AM EDT
To: "Earley, Anthony" <anthony.earley@pge-corp.com>
Cc: "Yackira, Michael" <MYackira@nvenergy.com>, "ted.craver@edisonintl.com" <ted.craver@edisonintl.com>, Nick Akins <nkakins@aep.com>, "Fanning, Thomas A." <TAFANNIN@southernco.com>, "thomas.farrell@dom.com" <thomas.farrell@dom.com>, "Crane, Christopher M:(BSC)" <christopher.crane@exeloncorp.com>
Subject: RE: EEI Leadership Call with John Podesta on 111(d) - SATURDAY, May 31, 1:00 pm EDT; PRE-CALL at 12:30 pm EDT

Tony: I tremendously appreciate your comments, and fully agree that the Administration is off to a horrible start in terms of how they are dealing with us on this proposed rule.

As you know, we were not invited to participate in the call you mentioned. I heard it characterized in the same way. Rather than continuing to work with us as a whole, I believe they are trying to go back to the old "divide and conquer" strategy. I commend you for the comments you made on the call strongly emphasizing that this is not the way to do business with us. This is an incredibly important and far-reaching rule which is focused on our industry, and I believe they need to deal with the industry as a whole. Brian Wolff conveyed this message to Podesta, which is the reason they are now saying that they want to talk with our Leadership. Having said that, I agree with you that we don't need a call without any substance that is only trying to check the box in their efforts to generate political support.

While I am very unhappy with the process, my primary concern, which we all share, is the substance. While we have heard over the past year bits and pieces about the direction in which they are heading, there will be much to digest when the proposed rule is issued. However, I am very concerned about yesterday's press reports suggesting that they intend to change the baseline from 2005 to 2013. While the numbers aren't out yet for 2013, we have achieved a substantial reduction in carbon emissions (somewhere in the neighborhood of 12 - 14%) during that timeframe. Politically, you would think that they would want to take credit for that achievement, and it certainly is a good talking point for our industry. If they change the baseline to 2013, they will take away all that we have achieved, and we all know that we did that through a very weak economy, lower gas prices and the mercury/MACT rule. Press reports suggest a targeted goal of 6% by 2020, which would exceed the Waxman/Markey numbers and the President's former target of 17% from 2005 levels by the year 2020. When you add up the numbers, it is not a huge increase by 2020, but again, the reports suggest a much higher target for 2030. If they are looking at a 25% reduction from 2013 levels (as reported), it would be much higher than the Waxman/Markey target. As you know, since we deal with long-term assets, time frames are incredibly important to us, flexibility mechanisms notwithstanding. While I don't want to prematurely jump-the-gun, and you and the Leadership are responsible for final policy decisions, I felt it important to raise these issues. As you indicated, there will also be many other issues for us to consider, as we did collectively in the mercury rule.

I apologize for the last minute scheduling for today's call – they dictated the time. Your suggestion to change it to Sunday night might be a good one, although they will continue their campaign to build political support over the weekend. They were originally going to have the President roll this out on Monday, but I understand they have now backed away from that strategy. We will check in with them this morning and keep you posted.

Thank you again for being “Horatio at the Bridge” at the first encounter.

-----Original Message-----

From: Earley, Anthony [<mailto:anthony.earley@pge-corp.com>]

Sent: Saturday, May 31, 2014 12:40 AM

To: Kuhn, Thomas

Cc: Yackira, Michael; ted.craver@edisonintl.com; Nick Akins; Fanning, Thomas A.; Earley, Anthony; thomas.farrell@dom.com; Crane, Christopher M:(BSC)

Subject: Re: EEI Leadership Call with John Podesta on 111(d) – SATURDAY, May 31, 1:00 pm EDT; PRE-CALL at 12:30 pm EDT

Tom -

I cannot make the call tomorrow but I wanted to give you my reaction to this evening's call.

I can't remember a call that insulted our industry's intelligence more than that one. They did not say one thing that we didn't know already and gave us absolutely no useful info on what the rule would say. Rather than engage us as partners in trying to formulate an incredibly important policy discussion, they told us that we were the biggest carbon polluter and we should jump on their bandwagon. It was a blatantly political presentation rather than an effort to treat us as partners. I think the deafening silence when they asked for questions and comments spoke volumes.

As an industry, I think we have to be at the table, but we are not off to a good start. I think we should let them know we are disappointed in the call today and decline to ask our members to participate tomorrow. I would suggest a Sunday

afternoon or evening call to send the message that we don;t intend to be rolled on this one.

Tony

Sent from my iPad

On May 30, 2014, at 10:23 PM, "Igoe, Joanne"
<JIgoe@eei.org<<mailto:JIgoe@eei.org>>> wrote:

We have been requested by John Podesta to convene a call Saturday afternoon at 1 pm (EDT) with him and other senior White House officials regarding EPA's pending release of the 111(d) GHG emission reduction guidelines proposal. We anticipate that this call will be very different than the series of general outreach calls White House staff currently are holding with various stakeholder groups and individual CEOs in our industry. We also expect to obtain specific details on key issues underlying the proposal.

I apologize for the late notification, but under the circumstances I think you will agree with me that it is worth our collective time and commitment. To prepare for the 1 pm call, we will hold a 12:30 pm pre-call. Specific call information is listed below.

12:30pm Pre-Call: DIAL: 1-877-418-3859; ask for the EEI Leadership Call;

1:00pm Podesta Call: DIAL: 1-800-860-2442; ask for the EEI/Kuhn Call.

I suspect you are current on the policy initiative in play via recent press reports and through conversations with your respective teams. Tomorrow's call is a fundamental step in what will be an intense, CEO-level dialog regarding how best to engage within the membership and with the Administration on this important issue. It is vital that our discussion with John Podesta include coverage of the most critical issues underlying the proposal, including the following:

- How EPA has defined the best system of emissions reduction (BSER) in setting the reduction guidelines
- Emission reduction guidelines for states
- Compliance timeframes (including recognition of emission reduction investments that have already been made)

- Baseline
- Compliance flexibility (including recognition of early action)

I hope that your schedule will permit you to participate in tomorrow's calls. In the interim, please contact me (202-508-5555) with any questions. Thank you for your continued leadership on this important issue.

PG&E is committed to protecting our customers' privacy.

To learn more, please visit

<http://www.pge.com/about/company/privacy/customer/>

To: Goffman, Joseph[Goffman.Joseph@epa.gov]
From: Wolff, Brian
Sent: Sat 5/31/2014 12:58:10 PM
Subject: Fwd:

Please do not share with anyone other than Gina. I believe now more than yesterday that we need her in Vegas to reset the table. She is great with them. The WH is very bad at outreach and proper messaging.

Please do not share below other than with her.

Thanks Joe

Brian

Sent from my iPhone

Begin forwarded message:

From: "Kuhn, Thomas" <TKuhn@eei.org>
Date: May 31, 2014 at 6:30:31 AM EDT
To: "Earley, Anthony" <anthony.earley@pge-corp.com>
Cc: "Yackira, Michael" <MYackira@nvenergy.com>, "ted.craver@edisonintl.com" <ted.craver@edisonintl.com>, Nick Akins <nkakins@aep.com>, "Fanning, Thomas A." <TAFANNIN@southernco.com>, "thomas.farrell@dom.com" <thomas.farrell@dom.com>, "Crane, Christopher M:(BSC)" <christopher.crane@exeloncorp.com>
Subject: RE: EEI Leadership Call with John Podesta on 111(d) - SATURDAY, May 31, 1:00 pm EDT; PRE-CALL at 12:30 pm EDT

Tony: I tremendously appreciate your comments, and fully agree that the Administration is off to a horrible start in terms of how they are dealing with us on this proposed rule.

As you know, we were not invited to participate in the call you mentioned. I heard it characterized in the same way. Rather than continuing to work with us as a whole, I believe they are trying to go back to the old "divide and conquer" strategy. I commend you for the comments you made on the call strongly emphasizing that this is not the way to do business with us. This is an incredibly important and far-reaching rule which is focused on our industry, and I believe they need to deal with the industry as a whole. Brian Wolff conveyed this message to Podesta, which is the reason they are now saying that they want to talk with our Leadership. Having said that, I agree with you that we don't need a call without any substance that is only trying to check the box in their efforts to generate political support.

While I am very unhappy with the process, my primary concern, which we all share, is the substance. While we have heard over the past year bits and pieces about the direction in which they are heading, there will be much to digest when the proposed rule is issued. However, I am very concerned about yesterday's press reports suggesting that they intend to change the baseline from 2005 to 2013. While the numbers aren't out yet for 2013, we have achieved a substantial reduction in carbon emissions (somewhere in the neighborhood of 12 - 14%) during that timeframe. Politically, you would think that they would want to take credit for that achievement, and it certainly is a good talking point for our industry. If they change the baseline to 2013, they will take away all that we have achieved, and we all know that we did that through a very weak economy, lower gas prices and the mercury/MACT rule. Press reports suggest a targeted goal of 6% by 2020, which would exceed the Waxman/Markey numbers and the President's former target of 17% from 2005 levels by the year 2020. When you add up the numbers, it is not a huge increase by 2020, but again, the reports suggest a much higher target for 2030. If they are looking at a 25% reduction from 2013 levels (as reported), it would be much higher than the Waxman/Markey target. As you know, since we deal with long-term assets, time frames are incredibly important to us, flexibility mechanisms notwithstanding. While I don't want to prematurely jump-the-gun, and you and the Leadership are responsible for final policy decisions, I felt it important to raise these issues. As you indicated, there will also be many other issues for us to consider, as we did collectively in the mercury rule.

I apologize for the last minute scheduling for today's call – they dictated the time. Your suggestion to change it to Sunday night might be a good one, although they will continue their campaign to build political support over the weekend. They were originally going to have the President roll this out on Monday, but I understand they have now backed away from that strategy. We will check in with them this morning and keep you posted.

Thank you again for being "Horatio at the Bridge" at the first encounter.

-----Original Message-----

From: Earley, Anthony [<mailto:anthony.earley@pge-corp.com>]

Sent: Saturday, May 31, 2014 12:40 AM

To: Kuhn, Thomas

Cc: Yackira, Michael; ted.craver@edisonintl.com; Nick Akins; Fanning, Thomas A.; Earley, Anthony; thomas.farrell@dom.com; Crane, Christopher M:(BSC)
Subject: Re: EEI Leadership Call with John Podesta on 111(d) – SATURDAY, May 31, 1:00 pm EDT; PRE-CALL at 12:30 pm EDT

Tom -

I cannot make the call tomorrow but I wanted to give you my reaction to this evening's call.

I can't remember a call that insulted our industry's intelligence more than that one. They did not say one thing that we didn't know already and gave us absolutely no useful info on what the rule would say. Rather than engage us as partners in trying to formulate an incredibly important policy discussion, they told us that we were the biggest carbon polluter and we should jump on their bandwagon. It was a blatantly political presentation rather than an effort to treat us as partners. I think the deafening silence when they asked for questions and comments spoke volumes.

As an industry, I think we have to be at the table, but we are not off to a good start. I think we should let them know we are disappointed in the call today and decline to ask our members to participate tomorrow. I would suggest a Sunday afternoon or evening call to send the message that we don't intend to be rolled on this one.

Tony

Sent from my iPad

On May 30, 2014, at 10:23 PM, "Igoe, Joanne"
<JIgoe@eei.org<<mailto:JIgoe@eei.org>>> wrote:

We have been requested by John Podesta to convene a call Saturday afternoon at 1 pm (EDT) with him and other senior White House officials regarding EPA's pending release of the 111(d) GHG emission reduction guidelines proposal. We anticipate that this call will be very different than the series of general outreach calls White House staff currently are holding with various stakeholder groups and individual CEOs in our industry. We also expect to obtain specific details on key issues underlying the proposal.

I apologize for the late notification, but under the circumstances I think you will agree with me that it is worth our collective time and commitment. To prepare for the 1 pm call, we will hold a 12:30 pm pre-call. Specific call information is listed below.

12:30pm Pre-Call: DIAL: 1-877-418-3859; ask for the EEI Leadership Call;

1:00pm Podesta Call: DIAL: 1-800-860-2442; ask for the EEI/Kuhn Call.

I suspect you are current on the policy initiative in play via recent press reports and

through conversations with your respective teams. Tomorrow's call is a fundamental step in what will be an intense, CEO-level dialog regarding how best to engage within the membership and with the Administration on this important issue. It is vital that our discussion with John Podesta include coverage of the most critical issues underlying the proposal, including the following:

- How EPA has defined the best system of emissions reduction (BSER) in setting the reduction guidelines
- Emission reduction guidelines for states
- Compliance timeframes (including recognition of emission reduction investments that have already been made)
- Baseline
- Compliance flexibility (including recognition of early action)

I hope that your schedule will permit you to participate in tomorrow's calls. In the interim, please contact me (202-508-5555) with any questions. Thank you for your continued leadership on this important issue.

PG&E is committed to protecting our customers' privacy.

To learn more, please visit <http://www.pge.com/about/company/privacy/customer/>

To: Wood, Allison D.[awood@hunton.com]
Cc: Drinkard, Andrea[Drinkard.Andrea@epa.gov]; Browne, Cynthia[Browne.Cynthia@epa.gov]
From: Goffman, Joseph
Sent: Fri 5/22/2015 11:04:04 PM
Subject: RE: Utility Air Regulatory Group meeting

Hello, again, Allison. Sorry to be testing your patience yet again, but having decided to stay in town the week of June 15, I should now have some availability to participate in the meeting if it turns out that your invitation still stands – or can be re-opened. Cynthia Brown can work with you on pinning down a time if you want to proceed. Many thanks.

Joc Goffman

Joseph Goffman

Associate Assistant Administrator for Climate

and Senior Counsel

Office of Air and Radiation

US EPA

Washington, DC.

From: Goffman, Joseph
Sent: Monday, May 18, 2015 12:08 AM
To: Wood, Allison D.
Cc: Drinkard, Andrea
Subject: Re: Utility Air Regulatory Group meeting

Hi, Allison. Thank you for the invitation and thank you for your patience in waiting for a

response. As it turns out, that week is already shaping up to be a tough one to make any additional commitments for, so I am hoping that I can get a rain check. Thanks.

- Joseph Goffman

Sent from my iPhone

On May 12, 2015, at 4:06 PM, Wood, Allison D. <awood@hunton.com> wrote:

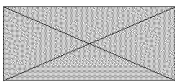
Dear Joe,

I just left a message on your voicemail and thought I would follow up with an email in case that is more convenient for you. As I explained in my voicemail, the Utility Air Regulatory Group (UARG) is having a large meeting on June 18-19 in our offices in Washington. In the past, EPA representatives have been willing to come and speak with UARG members about issues of importance to them. Naturally, the thing they are most interested in right now is the Clean Power Plan, and I was hoping you might be able to come and speak on that to them.

Could you please let me know if you are willing and available to do that? Thanks for considering this request.

Best regards,

Allison



Allison D. Wood

Partner

awood@hunton.com
p 202.955.1945

[bio](#) | [vCard](#)

Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037

[hunton.com](#)

To: Wolff, Brian[BWolff@eei.org]
From: Goffman, Joseph
Sent: Sat 5/31/2014 2:33:53 PM
Subject: RE:

Just to talked to her a got a positive response. Please get an invite into Matthew Fritz. Thanks.

From: Wolff, Brian [mailto:BWolff@eei.org]
Sent: Saturday, May 31, 2014 9:52 AM
To: Goffman, Joseph
Subject: Re:

This is time in Vegas

7:00 am Monday morning 6/9.

Sent from my iPhone

On May 31, 2014, at 9:02 AM, "Goffman, Joseph" <Goffman.Joseph@epa.gov> wrote:

Thanks, Brian. On it.

Sent from my BlackBerry 10 smartphone.

From: Wolff, Brian
Sent: Saturday, May 31, 2014 8:58 AM
To: Goffman, Joseph
Subject: Fwd:

Please do not share with anyone other than Gina. I believe now more than yesterday that we need her in Vegas to reset the table. She is great with them. The WH is very bad at outreach and proper messaging.

Please do not share below other than with her.

Thanks Joc

Brian

Sent from my iPhone

Begin forwarded message:

From: "Kuhn, Thomas" <TKuhn@eei.org>
Date: May 31, 2014 at 6:30:31 AM EDT
To: "Earley, Anthony" <anthony.earley@pge-corp.com>
Cc: "Yackira, Michael" <MYackira@nvenergy.com>, "ted.craver@edisonintl.com" <ted.craver@edisonintl.com>, Nick Akins <nkakins@aep.com>, "Fanning, Thomas A." <TAFANNIN@southernco.com>, "thomas.farrell@dom.com" <thomas.farrell@dom.com>, "Crane, Christopher M:(BSC)" <christopher.crane@exeloncorp.com>
Subject: RE: EEI Leadership Call with John Podesta on 111(d) - SATURDAY, May 31, 1:00 pm EDT; PRE-CALL at 12:30 pm EDT

Tony: I tremendously appreciate your comments, and fully agree that the Administration is off to a horrible start in terms of how they are dealing with us on this proposed rule.

As you know, we were not invited to participate in the call you mentioned. I heard it characterized in the same way. Rather than continuing to work with us as a whole, I believe they are trying to go back to the old "divide and conquer" strategy. I commend you for the comments you made on the call strongly emphasizing that this is not the way to do business with us. This is an incredibly important and far-reaching rule which is focused on our industry, and I believe they need to deal with the industry as a whole. Brian Wolff conveyed this message to Podesta, which is the reason they are now saying that they want to talk with our Leadership. Having said that, I agree with you that we don't need a call without any substance that is only trying to check the box in their efforts to generate political support.

While I am very unhappy with the process, my primary concern, which we all share, is the substance. While we have heard over the past year bits and pieces about the direction in which they are heading, there will be much to digest when the proposed rule is issued. However, I am very concerned about yesterday's press reports suggesting that they intend to change the baseline from 2005 to 2013. While the numbers aren't out yet for 2013, we have

achieved a substantial reduction in carbon emissions (somewhere in the neighborhood of 12 - 14%) during that timeframe. Politically, you would think that they would want to take credit for that achievement, and it certainly is a good talking point for our industry. If they change the baseline to 2013, they will take away all that we have achieved, and we all know that we did that through a very weak economy, lower gas prices and the mercury/MACT rule. Press reports suggest a targeted goal of 6% by 2020, which would exceed the Waxman/Markey numbers and the President's former target of 17% from 2005 levels by the year 2020. When you add up the numbers, it is not a huge increase by 2020, but again, the reports suggest a much higher target for 2030. If they are looking at a 25% reduction from 2013 levels (as reported), it would be much higher than the Waxman/Markey target. As you know, since we deal with long-term assets, time frames are incredibly important to us, flexibility mechanisms notwithstanding. While I don't want to prematurely jump-the-gun, and you and the Leadership are responsible for final policy decisions, I felt it important to raise these issues. As you indicated, there will also be many other issues for us to consider, as we did collectively in the mercury rule.

I apologize for the last minute scheduling for today's call – they dictated the time. Your suggestion to change it to Sunday night might be a good one, although they will continue their campaign to build political support over the weekend. They were originally going to have the President roll this out on Monday, but I understand they have now backed away from that strategy. We will check in with them this morning and keep you posted.

Thank you again for being "Horatio at the Bridge" at the first encounter.

-----Original Message-----

From: Earley, Anthony [<mailto:anthony.earley@pge-corp.com>]

Sent: Saturday, May 31, 2014 12:40 AM

To: Kuhn, Thomas

Cc: Yackira, Michael; ted.craver@edisonintl.com; Nick Akins; Fanning, Thomas A.; Earley, Anthony; thomas.farrell@dom.com; Crane, Christopher
M:(BSC)

Subject: Re: EEI Leadership Call with John Podesta on 111(d) – SATURDAY, May 31, 1:00 pm EDT; PRE-CALL at 12:30 pm EDT

Tom -

I cannot make the call tomorrow but I wanted to give you my reaction to this evening's call.

I can't remember a call that insulted our industry's intelligence more than that one. They did not say one thing that we didn't know already and gave us absolutely no useful info on what the rule would say. Rather than engage us as partners in trying to formulate an incredibly important policy discussion, they told us that we were the biggest carbon polluter and we should jump on their bandwagon. It was a blatantly political presentation rather than an effort to treat us as partners. I think the deafening silence when they asked for questions and comments spoke volumes.

As an industry, I think we have to be at the table, but we are not off to a good start. I think we should let them know we are disappointed in the call today and decline to ask our members to participate tomorrow. I would suggest a Sunday afternoon or evening call to send the message that we don't intend to be rolled on this one.

Tony

Sent from my iPad

On May 30, 2014, at 10:23 PM, "Igoe, Joanne"
<JIgoe@eei.org<<mailto:JIgoe@eei.org>>> wrote:

We have been requested by John Podesta to convene a call Saturday afternoon at 1 pm (EDT) with him and other senior White House officials regarding EPA's pending release of the 111(d) GHG emission reduction guidelines proposal. We anticipate that this call will be very different than the series of general outreach calls White House staff currently are holding with

various stakeholder groups and individual CEOs in our industry. We also expect to obtain specific details on key issues underlying the proposal.

I apologize for the late notification, but under the circumstances I think you will agree with me that it is worth our collective time and commitment. To prepare for the 1 pm call, we will hold a 12:30 pm pre-call. Specific call information is listed below.

12:30pm Pre-Call: DIAL: 1-877-418-3859; ask for the EEI Leadership Call;

1:00pm Podesta Call: DIAL: 1-800-860-2442; ask for the EEI/Kuhn Call.

I suspect you are current on the policy initiative in play via recent press reports and through conversations with your respective teams. Tomorrow's call is a fundamental step in what will be an intense, CEO-level dialog regarding how best to engage within the membership and with the Administration on this important issue. It is vital that our discussion with John Podesta include coverage of the most critical issues underlying the proposal, including the following:

- How EPA has defined the best system of emissions reduction (BSER) in setting the reduction guidelines
- Emission reduction guidelines for states
- Compliance timeframes (including recognition of emission reduction investments that have already been made)
- Baseline
- Compliance flexibility (including recognition of early action)

I hope that your schedule will permit you to participate in tomorrow's calls. In the interim, please contact me (202-508-5555) with any questions. Thank you for your continued leadership on this important issue.

PG&E is committed to protecting our customers' privacy.

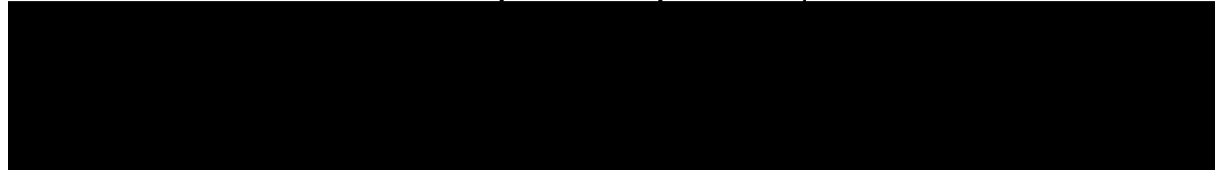
To learn more, please visit

<http://www.pge.com/about/company/privacy/customer/>

To: Wolff, Brian[BWolff@eei.org]
From: Goffman, Joseph
Sent: Sat 5/31/2014 1:02:29 PM
Subject: Re:

Thanks, Brian. On it.

Sent from my BlackBerry 10 smartphone.



Please do not share with anyone other than Gina. I believe now more than yesterday that we need her in Vegas to reset the table. She is great with them. The WH is very bad at outreach and proper messaging.

Please do not share below other than with her.

Thanks Joe

Brian

Sent from my iPhone

Begin forwarded message:

From: "Kuhn, Thomas" <TKuhn@eei.org>
Date: May 31, 2014 at 6:30:31 AM EDT
To: "Earley, Anthony" <anthony.earley@pge-corp.com>
Cc: "Yackira, Michael" <MYackira@nvenenergy.com>, "ted.craver@edisonintl.com" <ted.craver@edisonintl.com>, Nick Akins <nkakins@aep.com>, "Fanning, Thomas A." <TAFANNIN@southernco.com>, "thomas.farrell@dom.com" <thomas.farrell@dom.com>, "Crane, Christopher M:(BSC)" <christopher.crane@exeloncorp.com>
Subject: RE: EEI Leadership Call with John Podesta on 111(d) - SATURDAY, May 31, 1:00 pm EDT; PRE-CALL at 12:30 pm EDT

Tony: I tremendously appreciate your comments, and fully agree that the Administration is off to a horrible start in terms of how they are dealing with us on this proposed rule.

As you know, we were not invited to participate in the call you mentioned. I heard it

characterized in the same way. Rather than continuing to work with us as a whole, I believe they are trying to go back to the old “divide and conquer” strategy. I commend you for the comments you made on the call strongly emphasizing that this is not the way to do business with us. This is an incredibly important and far-reaching rule which is focused on our industry, and I believe they need to deal with the industry as a whole. Brian Wolff conveyed this message to Podesta, which is the reason they are now saying that they want to talk with our Leadership. Having said that, I agree with you that we don’t need a call without any substance that is only trying to check the box in their efforts to generate political support.

While I am very unhappy with the process, my primary concern, which we all share, is the substance. While we have heard over the past year bits and pieces about the direction in which they are heading, there will be much to digest when the proposed rule is issued. However, I am very concerned about yesterday’s press reports suggesting that they intend to change the baseline from 2005 to 2013. While the numbers aren’t out yet for 2013, we have achieved a substantial reduction in carbon emissions (somewhere in the neighborhood of 12 - 14%) during that timeframe. Politically, you would think that they would want to take credit for that achievement, and it certainly is a good talking point for our industry. If they change the baseline to 2013, they will take away all that we have achieved, and we all know that we did that through a very weak economy, lower gas prices and the mercury/MACT rule. Press reports suggest a targeted goal of 6% by 2020, which would exceed the Waxman/Markey numbers and the President’s former target of 17% from 2005 levels by the year 2020. When you add up the numbers, it is not a huge increase by 2020, but again, the reports suggest a much higher target for 2030. If they are looking at a 25% reduction from 2013 levels (as reported), it would be much higher than the Waxman/Markey target. As you know, since we deal with long-term assets, time frames are incredibly important to us, flexibility mechanisms notwithstanding. While I don’t want to prematurely jump-the-gun, and you and the Leadership are responsible for final policy decisions, I felt it important to raise these issues. As you indicated, there will also be many other issues for us to consider, as we did collectively in the mercury rule.

I apologize for the last minute scheduling for today’s call – they dictated the time. Your suggestion to change it to Sunday night might be a good one, although they will continue their campaign to build political support over the weekend. They were originally going to have the President roll this out on Monday, but I understand they have now backed away from that strategy. We will check in with them this morning and keep you posted.

Thank you again for being “Horatio at the Bridge” at the first encounter.

-----Original Message-----

From: Earley, Anthony [<mailto:anthony.earley@pge-corp.com>]

Sent: Saturday, May 31, 2014 12:40 AM

To: Kuhn, Thomas

Cc: Yackira, Michael; ted.craver@edisonintl.com; Nick Akins; Fanning, Thomas A.;

Earley, Anthony; thomas.farrell@dom.com; Crane, Christopher M:(BSC)

Subject: Re: EEI Leadership Call with John Podesta on 111(d) – SATURDAY, May 31, 1:00 pm EDT; PRE-CALL at 12:30 pm EDT

Tom -

I cannot make the call tomorrow but I wanted to give you my reaction to this evening's call.

I can't remember a call that insulted our industry's intelligence more than that one. They did not say one thing that we didn't know already and gave us absolutely no useful info on what the rule would say. Rather than engage us as partners in trying to formulate an incredibly important policy discussion, they told us that we were the biggest carbon polluter and we should jump on their bandwagon. It was a blatantly political presentation rather than an effort to treat us as partners. I think the deafening silence when they asked for questions and comments spoke volumes.

As an industry, I think we have to be at the table, but we are not off to a good start. I think we should let them know we are disappointed in the call today and decline to ask our members to participate tomorrow. I would suggest a Sunday afternoon or evening call to send the message that we don;t intend to be rolled on this one.

Tony

Sent from my iPad

On May 30, 2014, at 10:23 PM, "Igoe, Joanne"
<JIgoe@eei.org<mailto:JIgoe@eei.org>> wrote:

We have been requested by John Podesta to convene a call Saturday afternoon at 1 pm (EDT) with him and other senior White House officials regarding EPA's pending release of the 111(d) GHG emission reduction guidelines proposal. We anticipate that this call will be very different than the series of general outreach calls White House staff currently are holding with various stakeholder groups and individual CEOs in our industry. We also expect to obtain specific details on key issues underlying the proposal.

I apologize for the late notification, but under the circumstances I think you will agree with me that it is worth our collective time and commitment. To prepare for the 1 pm call, we will hold a 12:30 pm pre-call. Specific call information is listed below.

12:30pm Pre-Call: DIAL: 1-877-418-3859; ask for the EEI Leadership Call;

1:00pm Podesta Call: DIAL: 1-800-860-2442; ask for the EEI/Kuhn Call.

I suspect you are current on the policy initiative in play via recent press reports and through conversations with your respective teams. Tomorrow's call is a fundamental step in what will be an intense, CEO-level dialog regarding how best to engage within the membership and with the Administration on this important issue. It is vital that our discussion with John Podesta include coverage of the most critical issues underlying the proposal, including the following:

- How EPA has defined the best system of emissions reduction (BSER) in setting the reduction guidelines
- Emission reduction guidelines for states
- Compliance timeframes (including recognition of emission reduction investments that have already been made)
- Baseline
- Compliance flexibility (including recognition of early action)

I hope that your schedule will permit you to participate in tomorrow's calls. In the interim, please contact me (202-508-5555) with any questions. Thank you for your continued leadership on this important issue.

PG&E is committed to protecting our customers' privacy.

To learn more, please visit <http://www.pge.com/about/company/privacy/customer/>

From: Administrator McCarthy, Gina
Location: Alm Conference Room
Importance: Normal
Subject: FYI - Meetings with EEI
Start Date/Time: Thur 9/5/2013 1:00:00 PM
End Date/Time: Thur 9/5/2013 3:00:00 PM

SCt: Alison Kukla
EEI Ct: Brian Wolff, Senior VP - bwolff@eei.org, 202-508-5300

Staff:
Nichole Distefano (OCIR)
Michael Goo (OP)
Ken Kopocis (OW)
Janet McCabe, Joe Goffman (OAR)
Deputy Administrator, Lisa Feldt, Arvin Ganesan (OA)

Attendees:
Michael Yackira
Thomas Farrell
Thomas Fanning
Nick Akins
Lew Hay
Gery Anderson
Ralph Izzo
Gregory Abel
Anthony Early
Pat Collawn
Tom King
Chrisopher Crane

Run of Show:
9AM: 316(b)
10AM: GHG NSPS Issues

To: John McManus[jmmcmanus@aep.com]
Cc: McCabe, Janet[McCabe.Janet@epa.gov]; Andrea Field[afield@hunton.com]; Atkinson, Emily[Atkinson.Emily@epa.gov]
From: Drinkard, Andrea
Sent: Wed 6/11/2014 5:20:15 PM
Subject: RE: Invitation to June UARG Planning Workshop
Janet McCabe Event Form AAA.docx

Thanks, John. Just following up with the form. If you could fill it out and get it back to us this week that'd be great.

-Andrea-

Andrea Drinkard
 U.S. Environmental Protection Agency
 Office of Air and Radiation
 Email: drinkard.andrea@epa.gov
 Phone: 202.564.1601
 Cell: Personal Cell/email

-----Original Message-----

From: John McManus [mailto:jmmcmanus@aep.com]
 Sent: Saturday, June 07, 2014 12:58 PM
 To: Drinkard, Andrea
 Cc: McCabe, Janet; Andrea Field
 Subject: Re: Invitation to June UARG Planning Workshop

Andrea - 9 am on the 20th will definitely work, and a full hour will be great. Thanks for checking Janet's schedule and getting back to us.

John McManus

> On Jun 6, 2014, at 6:36 PM, "Drinkard, Andrea" <Drinkard.Andrea@epa.gov> wrote:

>

> This is an EXTERNAL email. STOP. THINK before you CLICK links or OPEN attachments.

>

> *****

> Hi John,

>

> Apologies for the delay in getting back to you. It's been a busy couple of weeks. I just spoke with Janet and checked the calendar and it looks like she'd be available at 9am on Friday, June 20. Would that time work for you? I assume you'd want her for the hour.

>

> If so, I'll forward a form for you all to fill out on Monday so we can prep for the event.

>

> Thanks so much and hope you have a wonderful weekend!

>

> Andrea Drinkard
 > Deputy Communications Director
 > EPA Office of Air and Radiation
 > 202.564.1601

>

> Original Message

> From: John McManus

> Sent: Friday, June 6, 2014 4:43 PM

> To: McCabe, Janet
 > Cc: Andrea Field; Drinkard, Andrea
 > Subject: RE: Invitation to June UARG Planning Workshop
 >
 > Janet - I thought I would check in on the invitation below to the UARG Annual Planning Workshop, which is two weeks away. I am sure the past couple of weeks have been incredibly hectic for you. Hopefully, things will settle down some with the proposal out and your schedule will allow some time to join us. Obviously there is a lot worth talking about.

>
 > Thanks.

>
 > John

>
 >
 > -----Original Message-----

> From: McCabe, Janet [mailto:McCabe.Janet@epa.gov]
 > Sent: Saturday, May 17, 2014 1:13 PM
 > To: John McManus
 > Cc: Andrea Field; Drinkard, Andrea
 > Subject: Re: Invitation to June UARG Planning Workshop

>
 > This is an EXTERNAL email. STOP. THINK before you CLICK links or OPEN attachments.

>
 > *****

> John--thanks so much for the invitation. We will scan the calendar quickly and get back to you.

>
 > -----
 > From: John McManus <jmmcmanus@aep.com>
 > Sent: Friday, May 16, 2014 8:08:26 PM
 > To: McCabe, Janet
 > Cc: Andrea Field
 > Subject: Invitation to June UARG Planning Workshop

>
 > Janet - it was good to talk to you yesterday. I am following up on my verbal invitation to the UARG Planning Workshop. The workshop begins at 1 pm on Thursday, June 19 and goes to 5 pm. We resume Friday morning June 20 at 8 am and go to noon. Our membership would very much appreciate the opportunity to have a dialogue with you on the key Clean Air Act programs that affect our industry. This would include the 111(d) proposal, assuming it is issued early in the month, implications of the CSAPR decision and anything you can share about the Agency's next steps, the rapidly approaching MATS compliance deadline, and other issues. Our agenda is flexible and we can accommodate your schedule if you are available.

>
 > We look forward to hearing from you.

>
 > John

Event Information Form

This form has been designed to assist in planning participation in events and activities.
This is not a confirmation of AAA Janet McCabe's attendance.

Basic Background

Name of Event	
Sponsoring Organization	
Date of Event	
Time of Event	
Expected time of remarks or participation by AAA McCabe	
Location (please include city/town and street address)	
Directions to the event (if appropriate, please also include relevant information about parking, the specific building, and best entrance to use)	
Where to meet POC	

Event Description and Role of the AAA

Brief description or outline of the event	
Brochure, invitation and/or other event material(s)	
Agenda and order of speakers and biography/information of other speakers	
Name of person introducing AAA McCabe	
Basic information about the role of the AAA official at the event. (For example, will they serve as a keynote speaker? Participate on a panel? Take part in a press conference? Tour a facility?)	
If the AAA official is a featured speaker, which topic(s) should they address and how long?	
What rules would the audience like to hear about?	
Will there be time for Q&A? If so, who will be moderating?	
Do you have a sense of the types of questions that may be asked?	
Recommendations on the use of visuals/PowerPoint. Should the AAA official plan on using a PowerPoint Presentation?	
What is the physical layout of the room (e.g. size, and format of the interaction; podium, seated in armchair dialogue, or at a table, etc.)	

About the Audience

Please tell us about the make-up of the audience for the event:	
Expected number in attendance at the event	
Will it be largely members of your organization?	
Will others be in attendance? If so, who will be at the event? (General public, Businesspeople, Educators, Families, Students – what grade level, Children – how old)	
Others? (Please describe)	
Is the event open to press?	

Contact Information

Your name:	
Telephone Number:	
Mailing Address:	
E-Mail Address:	
Cell Phone Number:	
Fax Number:	
Best way to reach you at the event?	

EPA Contact Person

Emily Atkinson, Administrative Assistant to Janet McCabe: 202-564-7404
 Andrea Drinkard, Public Affairs Specialist: 202-564-1601

From: Administrator McCarthy, Gina
Location: Alm Conference Room
Importance: Normal
Subject: Meetings with EEI
Start Date/Time: Thur 9/5/2013 1:00:00 PM
End Date/Time: Thur 9/5/2013 3:00:00 PM

SCt: Alison Kukla
 EEI Ct: Brian Wolff, Senior VP - bwolff@eei.org, 202-508-5300

Staff:

Nichole Distefano (OCIR)
 Michael Goo (OP)
 Ken Kopocis (OW)
 Janet McCabe, Joe Goffman, Peter Tsirigotis, Ellen Kurlansky (OAR)
 Deputy Administrator, Lisa Feldt, Arvin Ganesan (OA)

Attendees:

Michael Yackira	CEO	NV Energy
Thomas Farrell	Chairman, President, CEO	Dominion
Thomas Fanning	Chairman and CEO	Southern Company
Nick Akins	President and CEO	American Electric Power
Lew Hay	Executive Chairman	NextEra Energy
Gery Anderson	Chairman, President, CEO	DTE Energy
Ralph Izzo	Chairman and CEO	PSEG
Gregory Abel	Chairman, President, CEO	MidAmerican Energy
Anthony Early	Chairman, President, CEO	PG&E
Pat Collawn	Chairman, President, CEO	PNM Resources
Tom King	President	National Grid
Chrisopher Crane	President and CEO	Exelon
Tom Kuhn	President	EEI
Brian Wolff	Senior Vice President	EEI
Quin Shea	Vice President, Environment	EEI
Marv Fertel	President and CEO	NEI
Micheal Jay		
Bradley	President and Founder	MJB&A
Ann Loomis	Senior Advisor for Federal & Environmental Policy	Dominion
Randall LaBauve		Florida Power & Light

	Vice President of Environmental Services	Company
Kristen Ludecke	Vice President, Federal Affairs	PSEG

Run of Show:
9AM: 316(b)
10AM: GHG NSPS Issues

To: Mccarthy, Gina[McCarthy.Gina@epa.gov]
Cc: Kuhn, Thomas[TKuhn@eei.org]; Wolff, Brian[BWolff@eei.org]; Owens, David[DOWens@eei.org]; Shea, Quin[QShea@eei.org]; Fisher, Emily[EFisher@eei.org]
From: Bond, Alex
Sent: Mon 12/1/2014 3:10:32 PM
Subject: Docket No. EPA-HQ-OAR-2013-0602; Comments of the Edison Electric Institute
[EEI_111\(d\)_Comments_Final_12012014.pdf](#)

Administrator McCarthy,

Please find the comments of the Edison Electric Institute (EEI) on the proposed *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* issued by the Environmental Protection Agency in Docket No. EPA-HQ-OAR-2013-0602. 79 *Fed. Reg.* 34,830 (June 18, 2014) attached to this email. These comments also address the subsequently issued *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Notice of Data Availability*, 79 *Fed. Reg.* 64,534 (Oct. 30, 2014). EEI looks forward to continuing our dialog with the Agency on this complex and significant rulemaking.

Thank you!

Alex

--

Alex Bond
Manager, Air Quality & Climate Programs
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
202-508-5710

www.eei.org

Follow EEI on [Twitter](#), [Facebook](#), and [YouTube](#).



Edison Electric Institute

Power by Association®

From: Kukla, Alison
Location: Alm Conference Room
Importance: Normal
Subject: Meetings with EEI
Start Date/Time: Thur 9/5/2013 1:00:00 PM
End Date/Time: Thur 9/5/2013 3:00:00 PM

SCt: Alison Kukla
 EEI Ct: Brian Wolff, Senior VP - bwolff@eei.org, 202-508-5300

Staff:

Nichole Distefano (OCIR)
 Michael Goo (OP)
 Ken Kopocis (OW)
 Janet McCabe, Joe Goffman, Peter Tsirigotis, Ellen Kurlansky (OAR)
 Deputy Administrator, Lisa Feldt, Arvin Ganesan (OA)

Attendees:

Michael Yackira	CEO	NV Energy
Thomas Farrell	Chairman, President, CEO	Dominion
Thomas Fanning	Chairman and CEO	Southern Company
Nick Akins	President and CEO	American Electric Power
Lew Hay	Executive Chairman	NextEra Energy
Gery Anderson	Chairman, President, CEO	DTE Energy
Ralph Izzo	Chairman and CEO	PSEG
Gregory Abel	Chairman, President, CEO	MidAmerican Energy
Anthony Early	Chairman, President, CEO	PG&E
Pat Collawn	Chairman, President, CEO	PNM Resources
Tom King	President	National Grid
Chrisopher Crane	President and CEO	Exelon
Tom Kuhn	President	EEI
Brian Wolff	Senior Vice President	EEI
Quin Shea	Vice President, Environment	EEI
Marv Fertel	President and CEO	NEI
Micheal Jay Bradley	President and Founder	MJB&A
Ann Loomis	Senior Advisor for Federal & Environmental Policy	Dominion
Randall LaBauve		Florida Power & Light

	Vice President of Environmental Services	Company
Kristen Ludecke	Vice President, Federal Affairs	PSEG

Run of Show:
9AM: 316(b)
10AM: GHG NSPS Issues